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SPECIAL STUDY 20.7: NGNP BY-PRODUCTS AND EFFLUENTS STUDY

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APPROVALS

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ACRONYMS

CCTP	Climate Change Technology Program
GDP	Gross Domestic Product
H_2	Hydrogen
HPS	Helium Purification System
HTSE	High-Temperature Steam Electrolysis
HyS	Hybrid Sulfur
IDL	Idaho National Laboratory
IHX	Intermediate Heat Exchanger
IRP	Integrated Resource Plan
JAEA	Japan Atomic Energy Agency
MHIL	Mitsubishi Heavy Industries Ltd
MHR	Modular Helium Reactor
NGNP	Next Generation Nuclear Plant
PBMR	Pebble Bed Modular Reactor
PCHXs	Process Coupling Heat Exchangers
PNW	Pacific Northwest
SCFD	Standard Cubic Feet per Day
SCFY	Standard Cubic Feet per Year
SI	Sulfur Iodine
SMR	Steam Methane Reformer
SNL	Sandia National Laboratories
SOEC	Solid Oxide Electrolysis Cells
THTR	Thorium High Temperature Reactor
VLE	Vapor-Liquid Equilibrium
WECC	Western Electricity Coordinating Council
WSP	Water-Splitting Plant
WST	Water-Splitting Technologies

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20.7 NGNP BY-PRODUCTS AND EFFLUENTS STUDY

SUMMARY AND CONCLUSIONS

The objective of this study is to identify and quantify the products, by-products and waste streams produced by the NGNP and Hydrogen Plant and to identify potential markets or other disposition of these streams. Three different water-splitting technologies were considered for hydrogen production in this study: High Temperature Steam Electrolysis (HTSE), Hybrid Sulfur (HyS) and Sulfur-Iodine (S-I) processes.

To identify markets and quantify the products, by-products and waste streams, the size of the NGNP and Hydrogen Plant was first established. The Hydrogen Plant will be a commercial demonstration and must therefore demonstrate the following:

- Commercial materials of construction, component parts, and corrosion conditions
- Transport phenomena at a scale large enough to give experienced engineers assurance of a successful design
- Commercially manufactured catalyst(s)
- Long-term operability, product capacity, and product purity and marketability using commercially available feedstocks
- Interactions with upstream and downstream integrated units replicating the full-scale plant
- Commercial maintenance and reliability goals.
- A basis for estimating equipment capital and plant operating costs.

<u>Hydrogen Plant Size</u>

In the case of the Hydrogen Plant, there are two size limits that were considered in demonstrating the hydrogen production technology: the smallest practical scale to meet the requirements of a commercial demonstration and a single train of a full-scale plant. Materials development and specific component manufacturing techniques for some of the equipment are not fully developed and will limit fabrication capabilities. Most of the demonstration criteria will be met if the hydrogen plant is large enough to demonstrate that the critical pieces of equipment for each process can be fabricated. The definition of critical equipment here is that piece of equipment that limits the maximum capacity of the train and that is expected to pose a challenge with respect to one or more of the demonstration criteria.

The reference designs show that the critical pieces of equipment in almost all cases were process-coupling heat exchangers. One of these was the Decomposition Reactor in the HyS and S-I processes. Because current data shows this to be heat-transfer limited, it was treated as a heat exchanger. Using heat exchanger scaling considerations, including the concept of the equivalent hydraulic diameter, the following thermal duties were judged to correspond to the smallest practical Hydrogen Plant required for commercial demonstration and for a single train of a commercial plant. The HyS and S-I production rates should be the same for Process-Coupling Heat Exchangers (PCHXs) of the same duty. Differences shown are due to differences in assumptions in the source material.

Process	Critical Equipment	Smallest Practical Total PCHX Thermal Duty (MW_{th})	Commercial Train Total PCHX Thermal Duty (MW_{th})
High Temperature Electrolysis	Super Heater Heat Exchanger	13	13
Hybrid Sulfur & Sulfur Iodine	Sulfuric Acid Decomposer	5	50

Although the smallest practical Hydrogen Plant required for commercial demonstration will meet most of the technical demonstration criteria, it will not challenge the interaction between the nuclear reactor and the hydrogen plant. A 50 MWth process coupling heat exchanger will be a full scale unit. A nuclear powered water-splitting plant will use at most approximately 200 MW_{th} of the 500 MW_{th} output from a Pebble Bed Modular Reactor (PBMR). Such a plant will have no fewer than three or four trains of 50 to 66MW_{th}. This will be determined either by limits to fabrication capabilities for the process coupling heat exchanger or by availability and reliability considerations. Therefore, changes in demand on the nuclear heat source due to failures in the hydrogen plant will be in approximately 50 to 66 MW_{th} increments. A 50 MW_{th} demonstration plant can replicate the effect of demand swings on the heat source, while a 5 MWth plant cannot. Moreover, a small plant will not be an important step in demonstrating this technology to the public and in introducing the hydrogen economy. For these reasons, a 50 MW_{th} single commercial train demonstration is recommended for the HyS or S-I process. It was also determined that for the HTSE process, the smallest practical demonstration plant was the same size as a commercial train. Using the above sizing criteria, product hydrogen and by-product oxygen production rates are estimated to be as follows for each hydrogen production technology.

Technology	Hydrogen Production ($x10^6$ SCFD)		Oxygen Production ($x10^6$ SCFD)	
	Smallest Practical	Commercial Train	Smallest Practical	Commercial Train
High Temperature Electrolysis	8.0	8.0	4.0	4.0
Hybrid Sulfur	0.71	7.1	0.36	3.6
Sulfur Iodine	0.97	9.7	0.48	4.8

Potential Markets

Whatever technology or size is chosen for hydrogen production, electric power will be a major product of the NGNP. Forecasts for both the cost of a number of potential resource alternatives and market clearing prices in the Idaho region suggest a constant price of $60/MWe for NGNP electricity. This would result in long-term annual revenue of $71 million. A preliminary market analysis indicates there are limited opportunities for distributing the product hydrogen from the NGNP into the local market within reasonable transportation distances of the INL site. Hydrogen and oxygen production even from the smallest practical hydrogen plants for HyS or SI would be difficult to distribute and would exceed potential industrial demand. It would therefore be appropriate to use the NGNP hydrogen production to fuel a fleet of hydrogen-powered vehicles. This is a market that is non-existent today, but the NGNP hydrogen plant could encourage its emergence. If this could be achieved, an additional long-term revenue stream of $11 million per year might be realized.

Post-Production Gas Purification

Post-production purification of the hydrogen required by any of these markets will be substantial. Hydrogen purity requirements are generally 99.9% or greater. The High-Temperature Steam Electrolysis (HTSE) has less demanding requirements in this regard.

For HyS and S-I processes, caustic scrubbing of the gases followed by a disposable adsorbent bed will be required to remove sulfur compounds and iodine species, as appropriate. For all processes, the final step will require an additional drying.

Wastes

Daily operations at any facility will generate both liquid and solid waste streams requiring onsite treatment and disposal or offsite disposal, as the case may be. Anticipated waste streams associated with the nuclear reactor and the various hydrogen production technologies will include the following:

Nuclear Reactor Wastes & Emissions

- Tritium removed from the Helium coolant (≈115 Ci/yr)

- Radioactive waste material from core components

Hydrogen Production
- Gas purification wastes (i.e., caustic liquid wastes, spent carbon)
- Process stream blowdown
- Cooling system blowdown
- Pump seal water
- Solid waste (i.e., spent electrolyzers, absorber packing and catalysts)

Balance of Plant Waste Streams
- Feed water treatment process wastes (i.e., backwash/reject waste water)
- Spent water treatment media/membranes/resins
- Miscellaneous solid and universal waste
- Potentially contaminated storm water
- Oily wastes
- Sanitary wastes

The appropriate methods for treating or disposing of these wastes will need to be determined as the facilities' design approaches maturity.

Recommendations

1. The size of the NGNP Hydrogen Plant should be a full commercial train.
2. A local market for the product hydrogen must be developed. A fleet of buses using hydrogen in internal combustion engines should be investigated. A clear product specification for this market should be developed.
3. Feed pre-treatment, product purification, waste treatment and disposal should be included in the Hydrogen Plant conceptual design.
4. Focus research and development by selecting a preferred NGNP water-splitting technology by the beginning of the NGNP Conceptual Design Phase and executing a process design for the hydrogen plant including items in Recommendation 3.
5. Focus attention on developing practical flowsheets, gathering vital thermodynamic and phase equilibrium data, obtaining converged mass and energy balances, developing materials of construction, equipment design and involving industrial partners in the effort.

INTRODUCTION

The objective of this study is to identify and quantify the products, by-products and waste streams produced by the NGNP and Hydrogen Plant and to identify potential markets or other disposition of these streams. Quantification as well as characterization of these streams is necessary to identify markets or proper disposal. Therefore, the capacity of the hydrogen plant must be estimated to quantify products and waste streams. This, then, is the first task undertaken by this study. The hydrogen plant is intended to be a commercial demonstration and must therefore meet all the appropriate requirements for such an installation. This study enumerates these requirements, determines the smallest practical size that could be considered for such a plant, and considers an option of making the demonstration a full-scale commercial train. These options are considered for each of the leading water-splitting technologies: High-Temperature Steam Electrolysis (HTSE), the Hybrid Sulfur thermo-electrical cycle (HyS) and the Sulfur-Iodine thermo-chemical cycle (S-I).

Once the hydrogen and oxygen capacities are identified, potential markets for these gases as well as the power generated are surveyed and potential revenue streams estimated.

In addition, industrial gas markets depend upon the purity of the products produced. Achieving the required purity generally requires further processing. Additional purification processing of the products is therefore identified for each of the products and water-splitting technologies. Furthermore, this additional processing usually produces additional waste streams that may not be evident from the main process mass balances.

The nuclear reactor, hydrogen production and product purification generate wastes that must be disposed of properly. This study finally examines the nature, quantity and disposal options for these streams.

This study makes recommendations in those cases for which it is possible at this early stage of design development. In several other cases, firm recommendations are not advisable. In those cases, further study is recommended along with directions that the study might take.

20.7.1 SIZE OF THE NGNP PROTOTYPE HYDROGEN PLANT

This study assumes that the heat is supplied to the hydrogen plant at its battery limits at 900°C in the form of hot helium and is returned to the heat transport system. It also assumes that the heat transport medium is carried in a secondary loop and therefore does not pass through the core of the PBMR. Only the equipment in the hydrogen plant itself is considered. This choice has been made because it appears clear that the design, fabrication, and operation of commercial scale process coupling heat exchangers (PCHXs), regardless of the technology chosen, will be at least as challenging as that of the primary to secondary loop intermediate heat exchanger (IHX). The PCHXs will have virtually the same design temperature and pressure. Moreover, the PCHXs will have fluids such as sulfuric acid, sulfur dioxide, oxygen, steam and hydrogen to handle in addition to hot helium. In some cases the PCHXs will have to be designed to contain replaceable catalyst. Choices of the heat transfer medium and of reactor outlet temperature are discussed in greater length in Special Study 20.3, High Temperature Process Heat Transfer and Transport, Sections 1.1 and 3.2.

There are two sizing limits that should be considered in demonstrating the hydrogen production technology. One may choose to demonstrate at a scale that is the smallest practical to meet the requirements of a commercial demonstration. Alternatively, the demonstration may be of a single train of a full-scale plant. In either case, the demonstration criteria must be met. Typical criteria for commercial demonstration are:

- Materials of construction and component parts must be those that will be used in the full-scale plant.
- Transport phenomena (heat, mass, and momentum transfer) must be demonstrated at a scale sufficiently large that the operating data will give experienced engineers adequate assurance that a full scale unit can be successfully designed and built.
- Conditions for potential corrosion and deposition of materials should be replicated.
- Reaction kinetics must be demonstrated with commercially manufactured catalyst(s).
- The plant must demonstrate long-term operability, product capacity, and product purity using commercially available feedstocks.
- The plant must demonstrate the manufacturability of the commercial-scale equipment using commercially available materials.
- The demonstration plant must provide assurance of commercial acceptance and marketability of the full-scale plant products.
- Each process unit in the demonstration should be large enough that the interactions with upstream and downstream integrated units will adequately replicate similar interactions in the full-scale plant.
- Operation of the demonstration equipment should give assurance that the full-scale equipment will meet commercial maintenance and reliability goals.

- The demonstration plant should supply a reasonable basis for estimating equipment capital and plant operating costs.

Every processing plant is made up of a series of equipment pieces connected by piping and controlled by several sensors and control valves. Each piece of equipment carries out a certain unit operation and each unit operation consists of a combination of transport phenomena, reaction kinetics, and chemical and phase equilibria. The scalability of each unit operation depends upon several factors among which are the state of knowledge of the basic physical and chemical phenomena, the range of scale of practical experience, and the practical aspects of equipment fabrication. Some operations such as heat transfer are scalable over a very wide range; others like fluidized bed reactors have a much narrower scalable range. The unit operations one would expect to find in a water-splitting plant, with few exceptions, are all widely scalable.

The ability to manufacture equipment sometimes imposes a limit to size and introduces uncertainty in equipment design, especially when new or unfamiliar materials of construction are required. In the case of water-splitting plants that will require operations at very high temperatures and pressures by petrochemical processing standards, the manufacturability of equipment will be a key issue. In the case of the hydrogen plant, most of the demonstration criteria will be met if the plant is large enough to demonstrate the manufacturability of the critical pieces of equipment. The definition of critical equipment here is that piece of equipment that limits the maximum capacity of the train and that is expected to pose a challenge with respect to one or more of the demonstration criteria. The size of that piece of equipment is frequently set by manufacturing limitations. Other equipment in the train may be of equal capacity or the train may have to be split into several sub-trains depending upon size restrictions on downstream equipment.

20.7.1.1 Smallest Practical Hydrogen Plant Required for Commercial Demonstration

The smallest practical demonstration size limit for the hydrogen plant is set by that piece of equipment that limits the maximum capacity of the plant. For each of the leading water-splitting technologies, the critical piece of equipment may be different. The following discussion identifies the critical equipment, limiting process parameters and estimated hydrogen production rates for each technology.

<u>High-Temperature Electrolysis</u>

The following analysis is based on the latest published pre-conceptual design for the high-temperature electrolysis water-splitting technology entitled, "H2-MHR Pre-Conceptual Design Report: HTSE-Based Plant" and dated April 2006.[1] In the case of HSTE, the solid oxide electrolysis cells (SOEC) are expected to be small and many thousands of cells will be required to fulfill the requirements of commercial production.[2] The critical equipment will therefore be one of the heat exchangers that generate steam from the feed water and superheat it to the required process temperature and especially one of those that handle hot hydrogen or oxygen as well as steam. These heat exchangers are identified as "H_2 Recuperator," "Steam Generator," "Super Heater," "Sweep Heater," and "O_2 Recuperator", as shown in Figure 20.7-1.[3] Of these heat exchangers, the largest are the recuperators.

The recuperators account for more than half of the thermal duty required to heat the feed and sweep water from ambient temperature to the electrolyzer feed temperature. The blocks shown as single units on the flow diagram, however, must represent more than a single heat exchanger. In the case of the O_2 Recuperator, 30 % of the duty is for sweep water pre-heating, 46% for vaporization, and 24% for superheating. Each of these services will probably be carried out in separate piece of equipment. Similarly, the H_2 Recuperator shows condensation of the water out of the product hydrogen stream on one side of the exchanger with preheat and partial boiling of the feed water on the other side. These services too would also be carried out in separate pieces of equipment. It is not clear whether a temperature versus enthalpy analysis has been carried out on this flowsheet to determine whether the temperature differences are adequate. This suggests that not all of the heat shown as recovered in the recuperators can be recovered in practice. The overall duty of the process-coupling heat exchangers (PCHXs) may therefore be somewhat higher than that shown on the diagram.

According to the energy balance shown on this flowsheet, only about 9.7% of the thermal energy from the nuclear reactor is used to preheat feeds to the electrolyzer. That suggests that efforts at improving efficiency are better spent in the areas of generating and using electrical energy rather than making an extraordinary effort to design and test the recuperators. If the design of the recuperators proves to be problematic, these services can be carried out using thermal energy supplied by the secondary helium loop. For a first demonstration, this would be the preferred course. Recuperators can be added at a later date.

Of the remaining three heat exchangers, the Super Heater appears to be the critical piece of equipment. It has the largest thermal duty and will be heating a mixture of steam and hydrogen. It will also have the most challenging thermal design and will require at least two shell passes. The boiler may have a slightly larger heat transfer area, but its design is relatively straightforward. A rough estimate of the size of the Super Heater shows that an area of about 390 m^2 is required. If the exchanger is constructed of typical ¾ inch tubes 20 feet in length, the duty per tube is about 29kW.

For shell-and-tube heat exchangers the shell side and the tube side have different scale-up issues. As far as the tube side is concerned, a single tube, once characterized, can be multiplied indefinitely so long as the flow in each of the parallel tubes is equal. The scale-up issue on the tube-side is therefore distribution of the flow. A one hundred or more tube heat exchanger will present the tube-side flow distribution challenges that are representative of the commercial-scale design. The ratio of the tube-side head diameter to tube-side nozzle diameter should be at least about four (4). The one hundred or more tube heat exchanger will likely fit that requirement as well.

The shell side presents different issues. Common practice for designing segmental baffled shell and tube heat exchangers bases the effective shell-side heat transfer coefficient on the correlations for the heat transfer coefficient on the outside of a tube bundle in an "ideal" or fully-developed flow pattern. This ideal flow pattern occurs at the center of the bundle where the turbulence created by the presence of tubes upstream and downstream is no longer changing. Tubes in other locations will have somewhat different heat transfer coefficients. The effective shell-side coefficient is this ideal coefficient corrected by additional correlations for the tube bundle and baffle geometry.[4]

For shell side Reynolds numbers >100

$$h_{shell} = h_{ideal} * J_c * J_l * J_b$$

These "J" values are the correction factors for non-ideal flow patterns that occur due to the flow turning from direct flow across the tube to flow along the tube (as in the window area of the segmental baffle) or flow leakage around or along the baffles. Increasing the diameter of the tube bundle can minimize the need for these corrections. e.g. The cross flow correction Jc is approximately 1.0 when the baffle cut to shell diameter ratio is about 25%. This 25% baffle cut is commonly used in the chemical industry.

Because the tube length is fixed by the desire to use standard manufactured tube lengths and the number of tubes used in the design of heat exchanger must be large enough to produce flow patterns that are very similar to a full scale unit the heat exchanger is likely to necessarily contain 100 or more tubes.

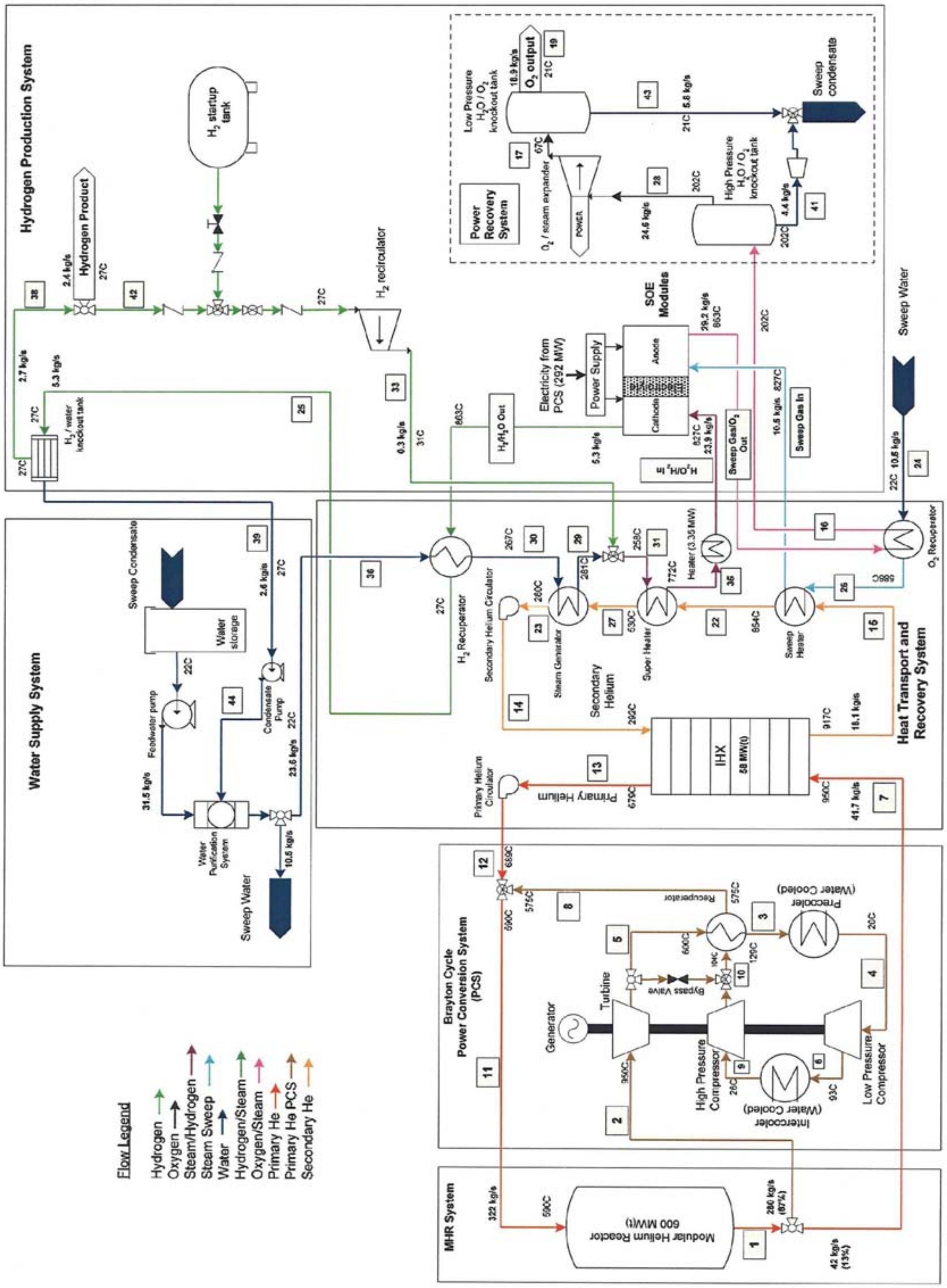

Figure 20.7-1 High Temperature Electrolysis Flowsheet

In the case where the shell side heat transfer coefficient is limiting, as is expected with helium to steam heat exchangers with helium on the shell side, one would demonstrate at a scale at which the effect of the heat exchanger shell no longer has a significant impact on the flow characteristics of the tube bundle. Both heat transfer coefficients and friction factors both for axial and cross flow have been correlated with the axial hydraulic diameter for tube bundles.[5] Here it is used as a characteristic shell side dimension. The issue of tube side distribution cannot be settled without considerably more detailed study. The axial hydraulic diameter is defined as:

$$\frac{4 \text{ x Axial Flow Area}}{\text{Wetted Perimeter}}$$

When the shell is considered as part of the wetted perimeter, it has a significant impact on bundles with small numbers of tubes. The relationship between the number of tubes and the effect on hydraulic diameter can be seen in Figure 20.7-2. As the ratio of the hydraulic diameters increases past 0.9, the incremental increase in the ratio is decreasingly affected by the number of tubes. Therefore, the minimum size that should be considered for a commercial demonstration by this criterion would be about 100 to 200 tubes.

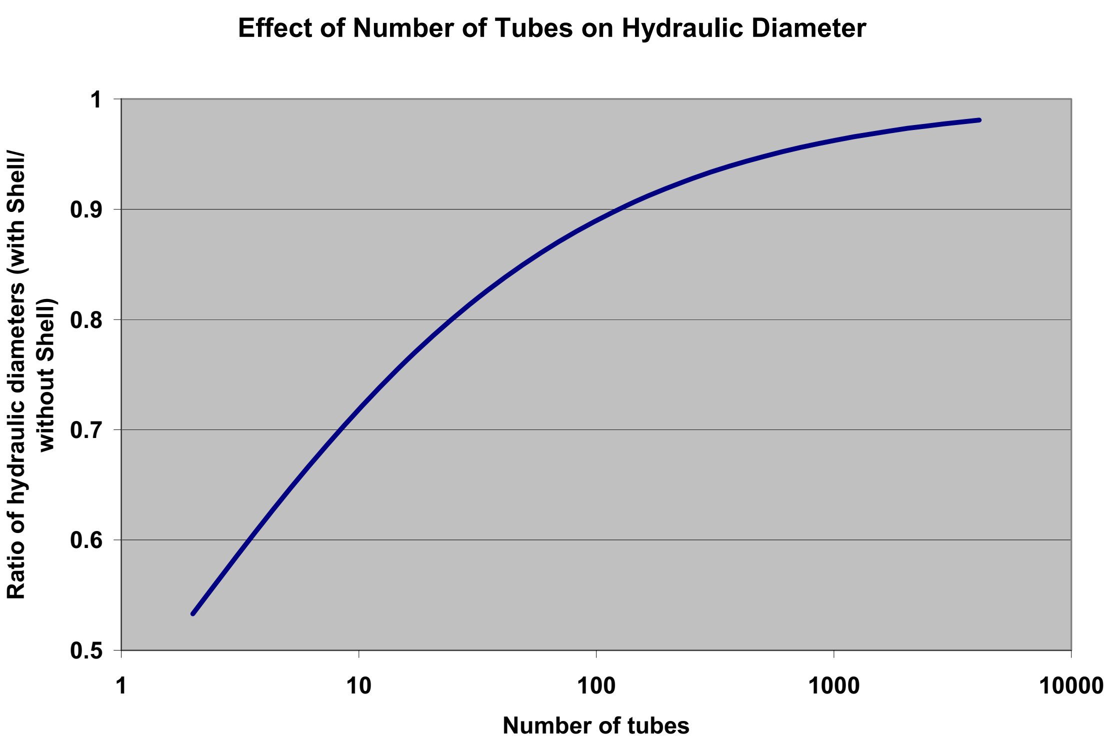

Figure 20.7-2 Influence of the Number of Tubes on the Hydraulic Diameter Shell Effect

For a 100 tube Super Heater, the duty would be about 2.9 MW_{th}. The corresponding duty for all three of the process-coupling heat exchangers in the secondary helium loop would be 5.7

MW_{th}. The corresponding recuperator duty is 7.5 MW_{th}. The total PCHX duty without recuperation would be 13.2 MW_{th}.

Production rates for this size unit:

Hydrogen: 0.224 kg/s or 8.0 million Standard Cubic Feet per Day (SCFD)

Oxygen: 1.78 kg/s or 4.0 million SCFD

Required electrolysis power input: 28 MWe

Required cell area: 11,400 m^2

The cells are arranged in stacks of 500 cells of 100 cm^2 per cell. Stacks are grouped in modules of 40 stacks and the modules are organized in units of eight modules. The total plot space required for the units would be about 250m^2.

Hybrid Sulfur (HyS)

The analysis in this section is based upon material provided by Westinghouse and prepared especially for this study. The material is attached to this report as Appendix A. The configuration of the HyS process is in some ways similar to that of HTSE (see Figure 20.7-3 and Figure 20.7-4). Each process has a step that requires high temperature heat and each also has a significant electrical input for electrolysis. In addition to electrolyzers, the HyS process requires an additional reactor, or decomposer, for sulfuric acid decomposition, towers for sulfuric acid scrubbing as well as scrubbing of the product gas streams to remove residual sulfur dioxide. In both the HyS and HTSE processes, the surface required for electrolysis is orders of magnitude larger than that required for heat transfer. A full-scale HyS plant (200MW_{th} thermal input to the decomposer) requires approximately 30 large electrolyzer units. Each of these units will contain about 250 cells. Scale-up would be accomplished by multiplying the number of cells in a unit.

Demonstration of a unit with the full 250 cells will probably not be needed. Therefore, a unit sized for even a rather small demonstration of the decomposer will easily be able to demonstrate commercial feasibility of the electrolyzers. The critical piece of equipment is therefore not in the electrolysis section of the HyS plant. Rather, the Decomposition Reactor (R-H002) will clearly limit the production capacity of the system and be the critical piece of equipment.

None of the other heat exchangers will pose scale-up issues; their design is straightforward. Likewise, the H_2SO_4 Column (A-H001) will be easily scaled. The sizing issues of this piece of equipment will involve choosing a diameter for the vapor flow, determining the number of equilibrium stages and determining the height of an equilibrium stage. The number of stages is calculated from vapor liquid equilibrium data which must be available before the plant can be designed. Both the diameter and height of an equilibrium stage depend upon the choice of contact device: the type of trays or packing. The methods for scaling up to large units from relatively small tests for these are well-known, especially for aqueous systems.

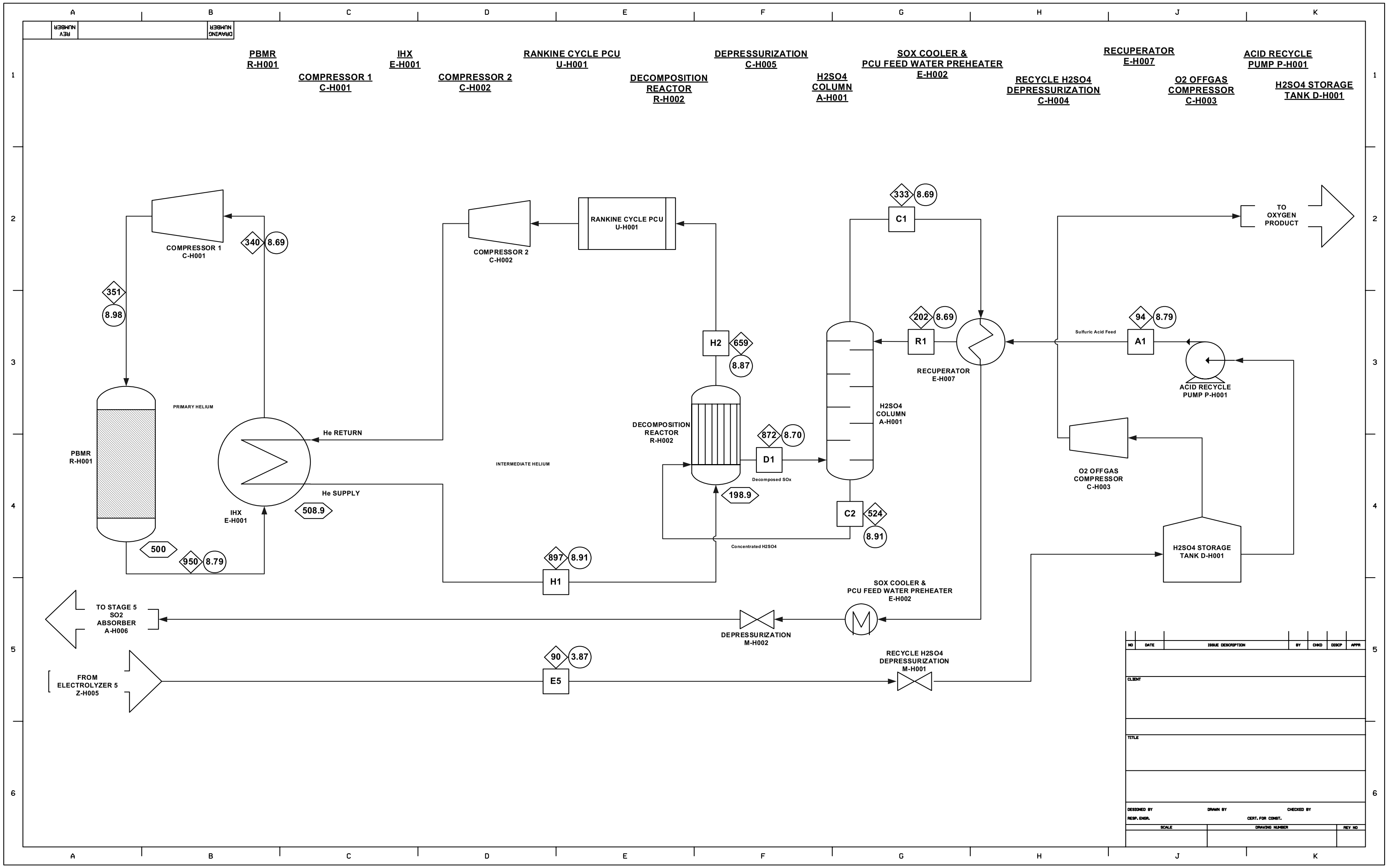

Figure 20.7-3 Hybrid Sulfur Process -- Decomposition Section

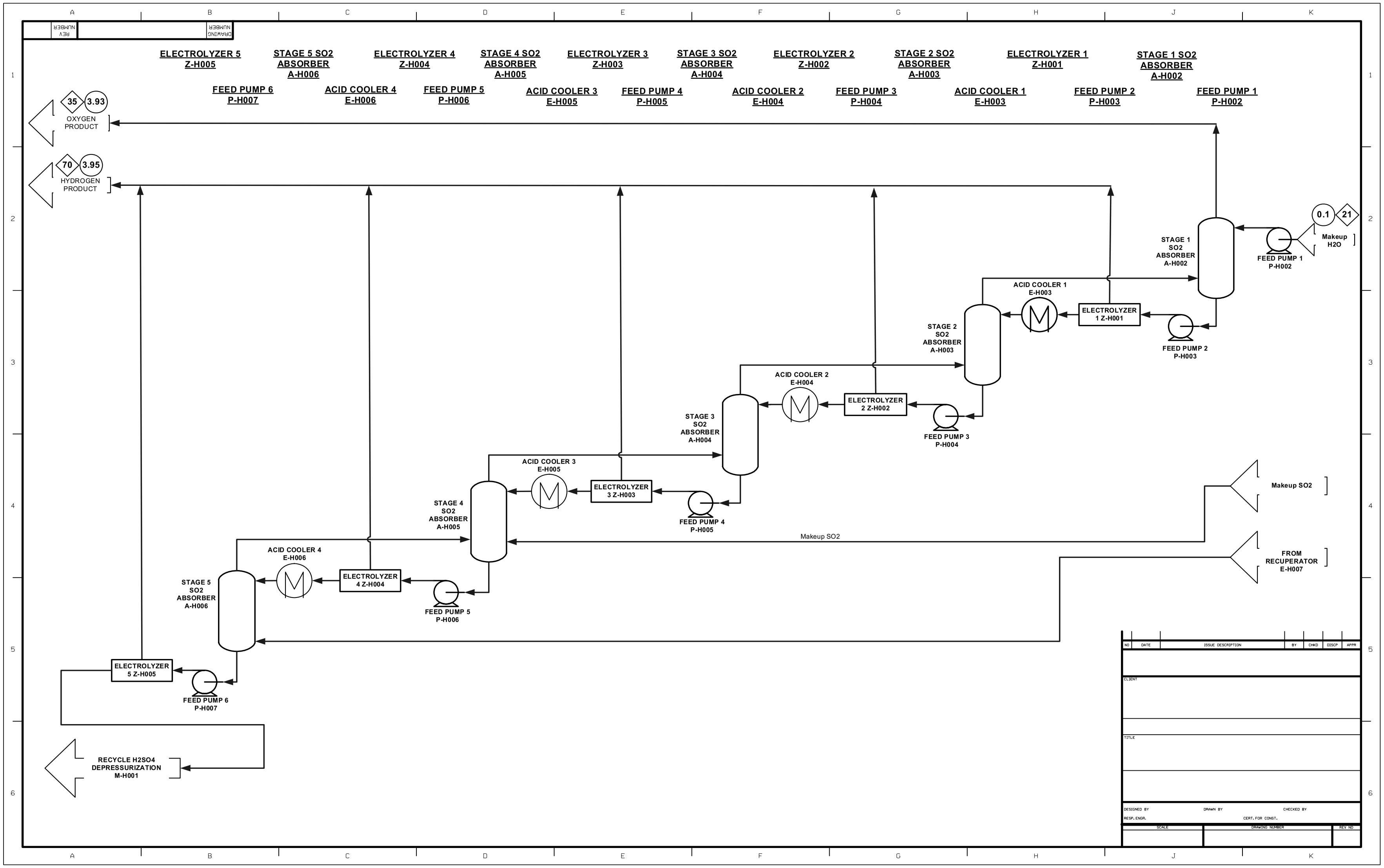

Figure 20.7-4 Hybrid Sulfur Process -- Electrolysis Section

The Decomposition Reactor is the only piece of equipment that might be a challenge with respect to the scaling demonstration criteria. The reactor's heat transfer surface will probably be constructed of a ceramic material, such as silicon carbide, due to its chemical resistance and strength at high temperature. Bonding and sealing between this material and the metal shell, tubesheet, or piping will be a major item for demonstration. The heat transfer coefficient will be significantly lower and the duty higher than the other exchangers in this plant.

Four different concepts have been proposed for the commercial Decomposition Reactor. One of these concepts is a microchannel ceramic design currently being developed by Ceramatec®, an advanced materials and electrochemical technology company located in Salt Lake City, UT. Ceramatec's decomposer concept is shown in Figure 20.7-5.

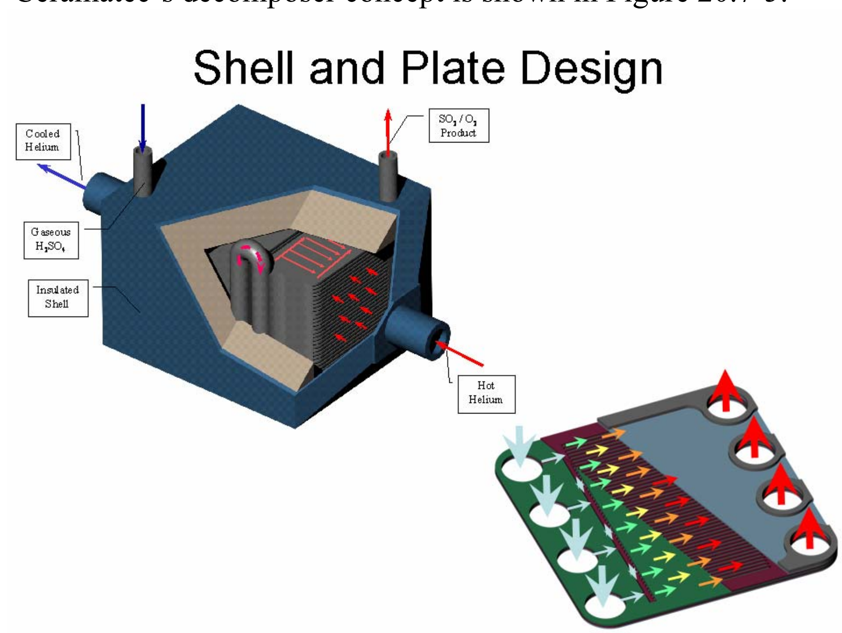

Figure 20.7-5 Ceramatec® Decomposer Concept

Figure 20.7-6 shows the Ceramatec® plan for development and demonstration of this design. Their engineers expect that a successful commercial-scale unit with a duty of 50MW_{th} can be constructed once a unit of 5 to 10 MW_{th} has been demonstrated.[6]

The second concept utilizes a decomposer with bundles of tubes containing catalyst. Each tube contains a smaller diameter inner to convey the reaction products (e.g., SO_2, O_2, H_2SO_4 and water). Bench-scale work with this decomposer design is currently being carried out at the Sandia National Laboratories on sulfuric acid decomposition[7]. The latest information available from them is that the reaction is heat transfer limited. Their work includes development of a commercial decomposer concept. Figure 20.7-7 shows the design of the Sandia bench-scale unit.

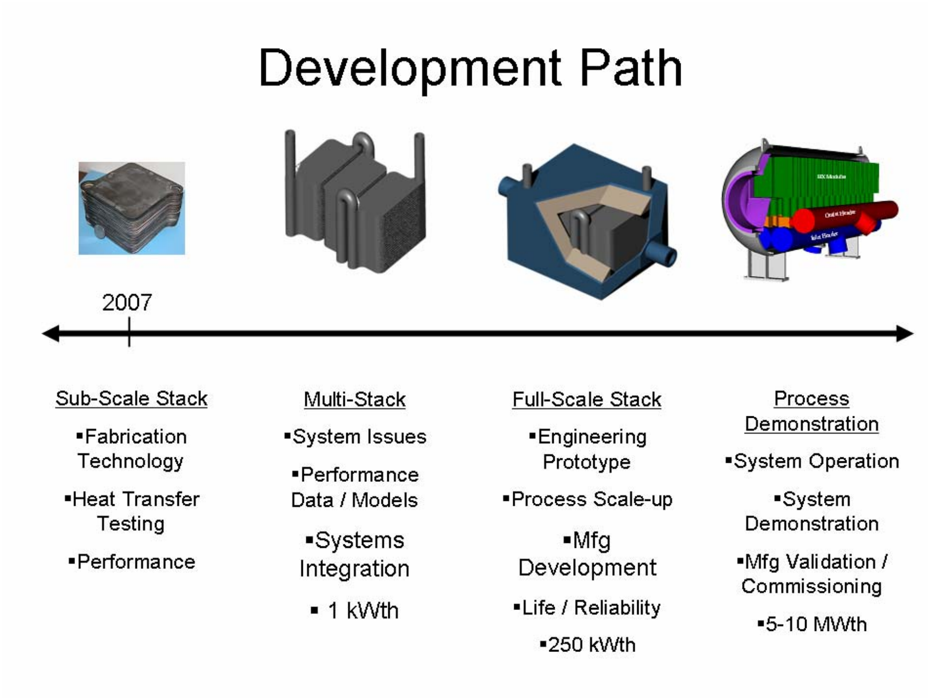

Figure 20.7-6 Ceramatec® Development Path

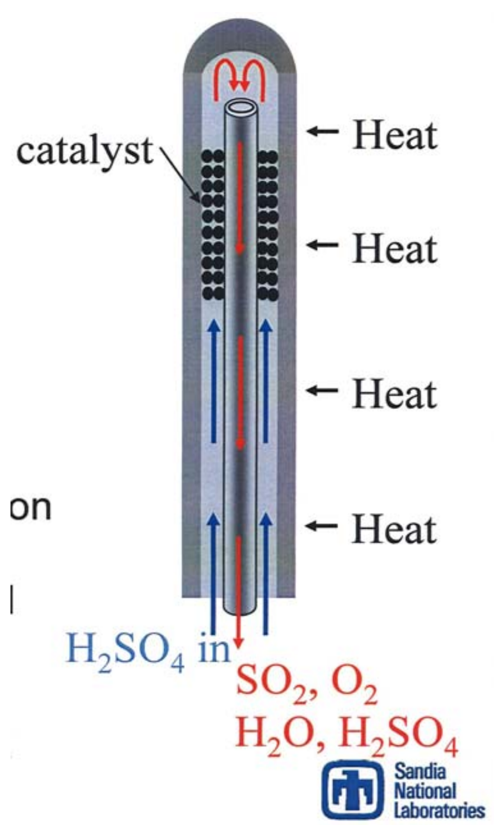

Figure 20.7-7 Sandia Bench-Scale Decomposer

The third concept is a commercial-scale design being developed by Westinghouse Electric Company.[8] This design is in some ways similar to the Sandia design except that the flow direction is reversed: the cold sulfuric acid enters through the central tube and, after vaporization, flows through the catalyst in the annular space. Figure 20.7-8 depicts the Westinghouse concept. This concept is the reference design for this study.

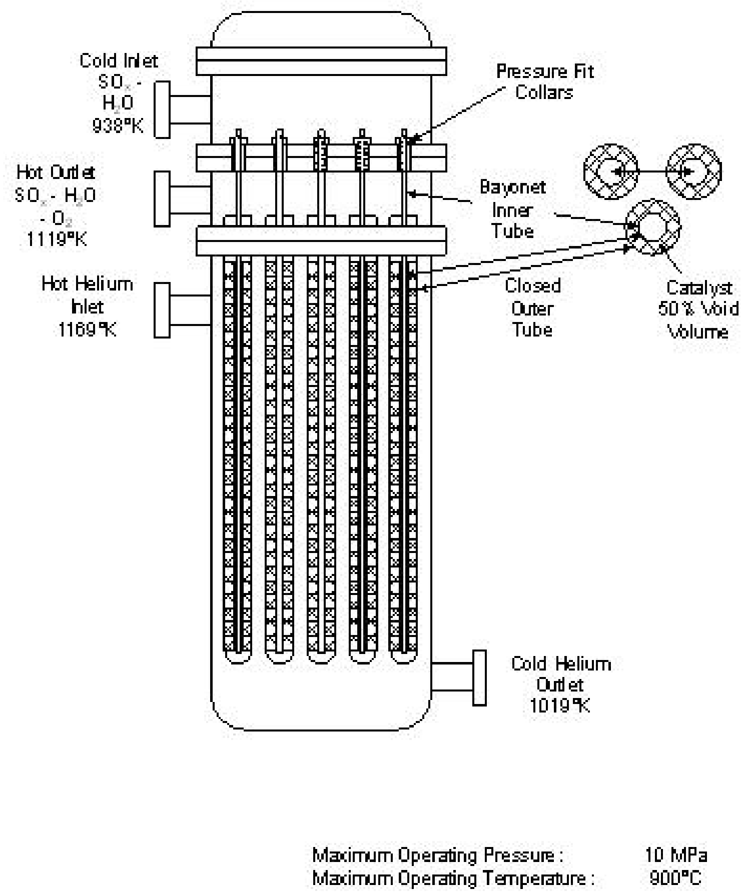

Figure 20.7-8 Westinghouse Decomposition Reactor Concept

The reasoning used for selecting the size of the smallest practical Decomposition Reactor required for commercial demonstration is similar to that used in the case of the HTSE heat exchangers, above. The design of this decomposition reactor is expected to be similar to a baffled shell-and-tube heat exchanger. In the case of this decomposer, the manufacture of tubes and construction of the tube bundles will be of critical concern. For this study, practical tube dimensions were selected based on conversations with a silicon carbide manufacturer.[9] The dimensions chosen were 63.5 mm OD for the outer, capped tube and 15.1 mm OD for the inner tube. The most important dimension is tube length. Tubes are now being manufactured of about 4 ¼ m in length. The manufacturer thought it would not be difficult to manufacture tubes about 6 m in length. Extrapolating for development driven by need over the next ten years, 10 meter tubes were chosen. From the strength and corrosion data provided, wall thicknesses were calculated: 4.3mm for the outer tube and 2mm for the inner. Residence time was checked using the latest information from Sandia National Laboratory.[10] An estimate was made of the heat transfer coefficient and duty for each tube. From these calculations, a duty of 42.6 kW was calculated for each tube. A Decomposition Reactor with a duty of 5 MW_{th} requires 118 tubes of this size. As recalled from Figure 20.7-2, this is a reasonable size to test pressure drop and heat transfer phenomena.

Production rates for a unit with a 5 MW_{th} decomposition reactor (based on Appendix A: the HyS mass and energy balance):

Hydrogen:	0.0198 kg/s	or	710,000 SCFD
Oxygen:	0.157 kg/s	or	355,000 SCFD
Required electrolysis power input:			1.36 MWe
Required cell area:			408.5 m^2

For a commercial HyS unit, the electrolysis cells are expected to be arranged in stacks of about 250 cells of 2.5 m^2 per cell. Each stack is contained in a rubber-lined pressure vessel with removable heads for cleaning and maintenance. Figure 20.7-9 shows a commercial Norsk Hydro electrolysis unit. Commercial HyS electrolyzers are expected to be similarly configured.[11]

Figure 20.7-9 Standard Norsk Hydro 5000 SCFH H_2 Electrolysis Unit

Sulfur-Iodine (S-I)

The analysis in this section is based on the most recent published information on the S-I process consisting of two reports: "H2-MHR Conceptual Design Report: S-I Based Plant"[12] and "Centralized Hydrogen Production from Nuclear Power: Infrastructure Analysis and Test-Case Design Study."[13]

Examination of the flowsheets and equipment lists in these reports shows that most of the equipment consists of pumps, turbines, drums and heat exchangers. The practicality of developing turbines or expanders that will operate successfully under these service conditions is doubtful. The other types of equipment mentioned are all widely scalable. In the Bunsen reaction section, five columns are shown that act as both absorbers and reactors. The only scaling issue of concern with these columns is liquid distribution. Once the relative liquid and vapor rates are known, there are well-known methods and techniques to ensure adequate liquid distribution and interphase contact.

For the reactive distillation section, the reactive distillation column itself may be a critical piece of equipment. However, there is currently insufficient available information to make this judgment. Reaction kinetics, chemical equilibrium and vapor-liquid equilibrium data for these species at several temperatures and the operating pressure would be required to make a theoretical determination of the equipment sizing. Moreover, continuous testing in an integrated plant, especially when trace impurities are present, may well invalidate the theoretical calculations. Therefore, the reactive distillation column should be considered a critical item until shown to be otherwise. Consequently, the size of the smallest practical hydrogen plant to demonstrate production as a commercial prototype based on the reactive distillation column can not be estimated.

Since scale up of distillation can be accomplished over very broad ranges, it is probable that the sulfuric acid decomposition reactor rather than the reactive distillation column will set the size of the smallest practical demonstration plant. Analysis of the flowsheets and decomposition reactor designs shows that the functions performed by the HyS decomposition reactor are matched exactly by the blocks H208A, H208B, H209, H210A, and H210B, as shown in Figure 20.7-10, below. Differences in performance of this section between the reports representing these technologies are due to one of three causes:

- differences in heat integration schemes
- differences in maximum process temperature
- differences in the thermochemical and equilibrium data used.

Intermediate temperatures in the heat exchangers shown on the S-I flowsheet for the blocks in question are not provided. The feasibility of the heat integration scheme, therefore, cannot be judged. Equally aggressive heat integration should give equal, or nearly equal, results in both processes. The temperature of the hot helium into the decomposer is 27K higher in the S-I flowsheet than in the HyS counterpart. This is an important factor in reactor performance, but it depends upon assumptions about the nature of the nuclear reactor from which the heat is supplied and the losses in the heat transport system. Given the same assumptions about these subsystems, the maximum process temperature will be the same in both cases.

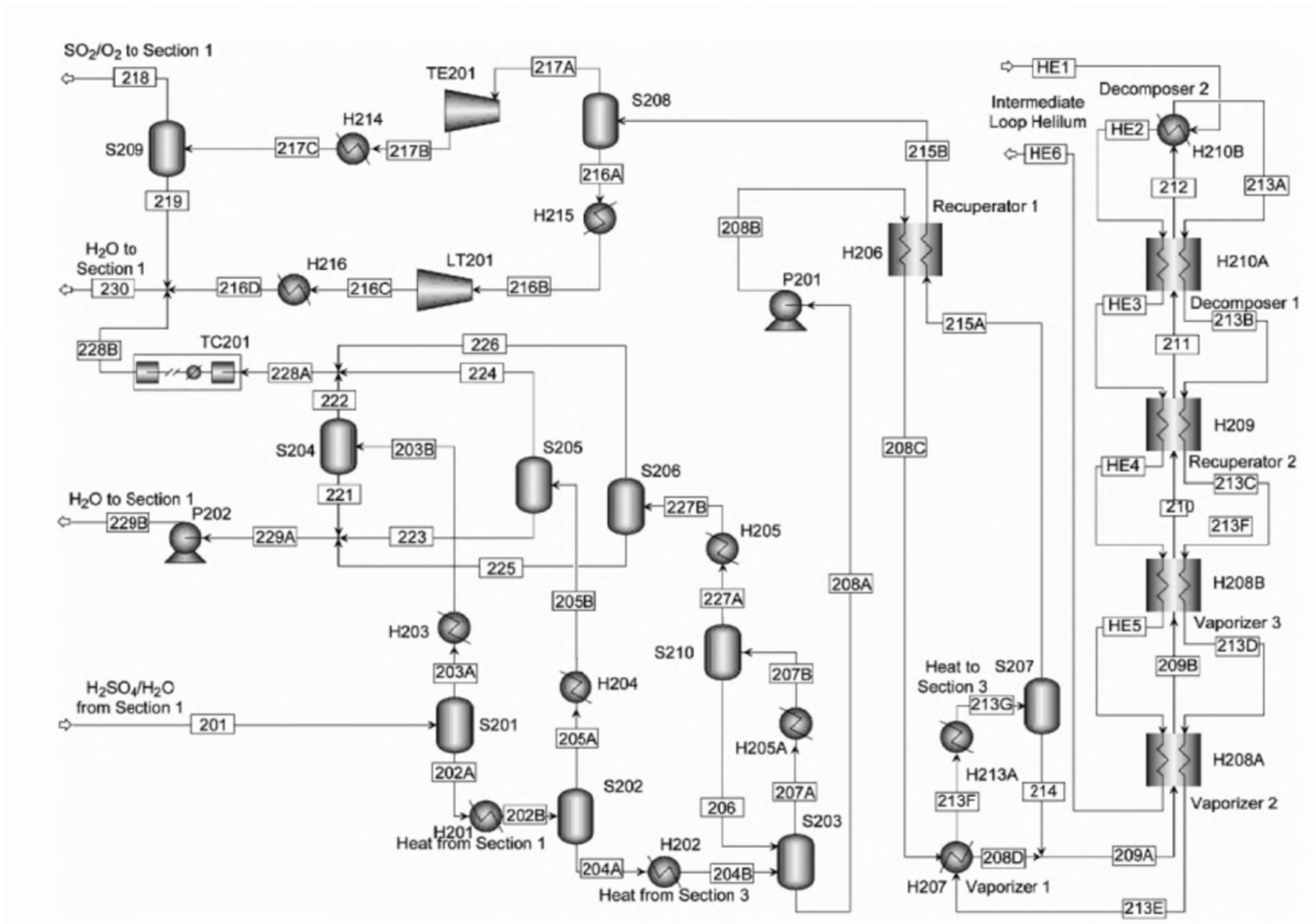

Figure 20.7-10 S-I Process Section 2 Flowsheet

The thermodynamic and phase equilibrium data for this system has been studied extensively by the team developing the HyS process and was used in the preparation of the mass balance used in this study.[14] This work was published after the publication of the S-I reports upon which this discussion is based. If an equally rigorous data development effort was made in preparation of the mass and energy balances for the S-I process, it is not mentioned in the reports. There are no substantial differences between the two processes with regard to the sulfuric acid decomposition step. With the same heat supply, decomposition will produce the same results in both processes. This section of the plant is interchangeable between the two processes. The discussion on the HyS decomposition reactor should therefore apply to the S-I process as well.

Production rates for a unit with a 5 MW_{th} decomposition reactor (based on information in Richards, *et.al.,* SI-Based Plant, April 2006)[15] :

Hydrogen:	0.0270 kg/s	or	966,000 SCFD
Oxygen:	0.214 kg/s	or	483,000 SCFD

Note that required inputs to other sections of the above processes as well as power requirements other than electrolysis have not been considered.

Mitsubishi Heavy Industries Ltd. and Japan Atomic Energy Agency have put forward a fourth alternative concept based on a tubular design for the sulfuric acid decomposer and a separate plate design for the sulfur trioxide decomposer. The scale-up principles are the same for the designs discussed here and therefore appropriate demonstration sizes for these designs are expected to be the same as those suggested above.[16]

20.7.1.2 Commercial Train

In sizing a commercial train, the question is how large, rather than how small one can make the critical piece of equipment and still have it operate successfully. For a HTSE system powered by a PBMR, about ten percent of the thermal energy from the reactor is used to heat feed steam and sweep gas provided that the heat recovery shown in the HTSE-Plant Report can be achieved.[17] In that case, the largest process-coupling heat exchanger would be the Boiler. The Super Heater would be nearly as large. Both heat exchangers would be reasonably sized with about 910 tubes, each tube being 19 mm in diameter and 6 meters in length. The Recuperators would be even larger, but these services would not be carried out in a single shell. A single train rated at about 50 MW_{th} for process-coupling duty would be required for each nuclear reactor. The hydrogen production would be about 2.0 kg/s or about 70 million SCFD. This is the size of a medium-to-large sized steam reformer with an output that would provide hydrogen for a refinery. Distribution of high pressure and temperature steam to the cells and reliance on a single heat exchanger train would probably not favor a single train in a commercial unit until adequate operating experience were gained. Early commercial designs would probably favor a plant with three to four heat exchange trains delivering steam to the electrolysis cells. A demonstration unit would probably consist of a single train with a process coupling duty of about 13.2 MW_{th}. If the demonstration did not include recuperation, this would be the same size as the smallest practical hydrogen plant required for commercial demonstration.

Presuming that the Decomposition Reactor is the critical piece of equipment for either the HyS or S-I process, we can make an estimate of the size of the largest unit. A 50 MW_{th} decomposition reactor will have approximately 2500 ceramic fingers with each finger about 65 mm in diameter and 10 meters long. The vessel will be about 4½ meters in diameter and have a metal wall thickness of about 12 to 13 centimeters. From a process perspective, there are several reasons to limit the diameter of the vessel. As the number of tubes and the diameter increases, flow distribution in the tubes becomes more difficult. In addition, the baffle spacing may become small and the variation in velocity across the tube bundle will be large. Alternative shell baffling patterns have to be considered with a resulting loss in heat transfer effectiveness. From a mechanical viewpoint, there are design and fabrication limits that would be encountered, especially with regard to the tubesheet thickness. For a first commercial plant, a 50 MW_{th} decomposer would be a reasonable choice for a train size. The production rate from one train would be 0.198 to 0.270 kg/s of hydrogen (depending upon the material balance one uses) and 0.793 to 1.08 kg/s for a four-train plant. This is equivalent to 28 to 39 million SCFD in common industrial units.

The question remains as to whether the first commercial operation of this technology should be of a commercial train or of the smallest practical plant to demonstrate production as a commercial prototype. In the petrochemical and chemical industry, the tendency is to build the smallest practical plant that will meet the demonstration goals. This provides an adequate commercial demonstration of the technology and a smaller cost and risk. In many cases, this is executed by retrofitting an existing, outmoded unit. In the case of the NGNP, there are additional considerations that are not usually encountered by process industry demonstration plants. One issue is the destination of the hydrogen and oxygen products. This will be discussed in more detail below, but it should be noted that the production of both hydrogen and oxygen from even the small demonstration units will be large with respect to the available markets. A small demonstration unit will facilitate the demonstration of several hydrogen-producing technologies at a lower cost and with less disruption. Nevertheless, there are advantages in making the first demonstration plant a commercial train.

The most important factor that must be considered is the influence of upsets in the operation of the hydrogen plant on the nuclear reactor. A small hydrogen plant will not fully demonstrate interactions with the nuclear reactor. This is not a consideration from the point of view of the hydrogen plant, but it may be important in demonstrating nuclear safety cases and in licensing issues. A 50 MWth process coupling heat exchanger will be a full scale unit. A nuclear powered water-splitting plant based on either HyS or S-I will use approximately 200 MW_{th} of the 500 MW_{th} output from a Pebble Bed Modular Reactor (PBMR). Such a plant will have no fewer than three or four trains of 50 to 66MW_{th}. This will be determined either by limits to fabrication capabilities for the PCHX or by availability and reliability considerations for the plant. Therefore, major changes in demand on the nuclear heat source due to failures in a commercial hydrogen plant will be in approximately 50 to 66 MW_{th} increments. A 50 MW_{th}

demonstration plant will replicate one train of a full commercial plant and therefore will imitate the effect of demand swings on the heat source. A 5 MWth plant cannot do this.

For the same or similar reasons, a commercial scale train will better replicate the configuration that will have to be licensed for any subsequent commercial plant.

In the chemical industry funding and siting are less encumbered by the need for broad understanding and acceptance than in the nuclear industry. Therefore demonstration projects are built for technical and product marketing purposes, not to gain wide support. In developing a hydrogen economy, however, broad acceptance is important and a demonstration that is convincing to the technically unsophisticated is valuable. A commercial train demonstration will be broadly convincing. It will also provide better data on plant operating costs including operating personnel as well as on security and safety. It is not possible to make a firm recommendation in this matter without a better understanding of the relative importance of these benefits and drawbacks. Unless cost and the disposition of hydrogen product are overriding concerns, a full-size train demonstration is preferred and hence recommended as the reference.

20.7.2 POTENTIAL MARKETS FOR NGNP PRODUCTS

20.7.2.1 Electricity

Whatever technology or size is chosen for hydrogen production, electric power will be a major product of the NGNP. For a 50 MW_{th} sized commercial train for the hydrogen plant demonstration, about 160 MWe of export power would be available. When the hydrogen plant is down for a planned or unplanned outage, the maximum power for export is about 200 MWe. Power from the NGNP can be traded on the wholesale, short-term market at the Mid-Columbia trading hub or contracted to the Idaho Power Company – the regional service utility. Predicting the market or contract price of electricity when production comes on-line in 2018 timeframe relies on others' forecast and judgment. Based on discussions with personnel from the Idaho Power Company[18] and their Integrated Resource Plan (IRP) for 2006[19], two approaches serve to bracket such a forecast. The first is based on the forecast for the levelized costs of a number of potential resource alternatives considered in Idaho Power's 2006 IRP. Using comparably sized alternatives that range from regional pulverized coal plants to geothermal plants, the 30-year levelized prices are in the range of 55 to 65$/MWh (2006$). The second approach applies the forecasted market clearing prices for the regional Idaho bubbles within the Western Electricity Coordinating Council (WECC), which are included in the same IRP reference. Using the Pacific Northwest (PNW) Idaho South Region for 2018, off-peak prices vary from 57 to 76$/MWh (current year $) over the year whereas on-peak prices vary from 76 to 108$/MWh. Assuming a few percent underlying inflation, the off-peak prices in 2006$ are in the same range as for the alternative generation options above. For an initial power revenue estimate, a constant price of 60$/MWh is suggested. Using a conservative capacity factor of 85% and a 160 MWe export power level, the annual revenue would be about $71 million /yr for a long-term projection. However, during the early years of operation, the plant is expected to have higher unplanned outages typical of first-of-a-kind plants. Moreover, the operating priorities will favor system and process testing and will therefore result in a lower capacity factor. In addition, uncertainty about availability will mean the price of the power will likely be based on a non-firm basis. Hence, for the first six years, an average capacity factor of 75% and a power price of 45$/MWh are judged to be appropriate for initial estimates. This results in an annual revenue during that six year period of $47 million / yr. More detailed information and sources may be found in Appendix B.

20.7.2.2 Hydrogen

A preconceptual market analysis indicates there are limited opportunities for distributing the product hydrogen from the NGNP into the local market within reasonable transportation distances of the INL site. Table 20.7-1 NGNP Gas Production Rates presents a review of the expected range of quantities of gases to be produced for three water-splitting technologies and for the smallest practical demonstration unit as well as for a commercial train as discussed in the sections above.

The production rates of hydrogen shown for the HTSE process can be misleading. In the case of the HTSE cycle, considerably more of the energy from the PBMR is used to make hydrogen than for the other technologies. This is because the critical piece of equipment in each case is in the heat transfer train and the fraction of thermal energy used to split water in each case is quite different. In the case of HyS, the ratio of thermal energy to electrical energy is over 3.6. For HTSE, the ratio is 0.2 for full recuperation and 0.46 for no recuperation. The size of the demonstration unit is dependent upon the critical equipment, not on the hydrogen production.

Table 20.7-1 NGNP Gas Production Rates

Size	Technology	Hydrogen (10^6 SCFD)	Oxygen (10^6 SCFD)
Smallest Practical	HTSE	8.0	4.0
	HyS	0.71*	0.36*
	S-I	0.97*	0.48*
Commercial Train	HTSE	8.0	4.0
	HyS	7.1*	3.6*
	S-I	9.7*	4.8*

*These are values derived from diverse sources which have not been reconciled. The production quantities for each gas are expected to be equal for both technologies of the same size. See the discussion under "**Sulfur Iodine**," above.

Potential uses for hydrogen are generally wide-ranging (See Table 20.7-1). Modest quantities of hydrogen are used in glass and chemical production. Somewhat larger quantities are used in metal processing and fabrication. These applications are often served by compressed gas packaging (i.e. cylinders and "tube trailers"). "Tube trailers" are tractor trailers with large high pressure cylinders permanently attached. Food production via hydrogenation of fats and oils often requires liquid tanks or small reforming plants that generate hydrogen at the consumption site. Hydrogen used as transportation fuel in fuel cell vehicles is typically high pressure (e.g. 5000 PSI) and high purity.

Production of the transportation fuels by petroleum refineries typically use 10's of millions to 100 million SCFD of hydrogen. These applications are almost exclusively served by on-site hydrogen generation or by pipelines that are served by steam reformers. Refining operations using hydrogen create a large amount of waste fuel gas containing carbon monoxide, methane, light hydrocarbon gases, some hydrogen, and inerts. This fuel gas is commonly burned in furnaces. The steam methane reformer is one of the chief sinks for this gas. Even when refineries buy hydrogen over-the-fence from gas producers, they can sell the heating value of the fuel gas to the reformer operator. Therefore, refining would not usually be a good market for NGNP hydrogen.

Table 20.7-2 Uses of Hydrogen

- **Chemical and Pharmaceutical Industry**
  - Production of substitute natural gas
  - Production of high-density polyethylene and polypropylene
- **Electrical Industry**
  - Fuel gas in production and sealing of glass tubes
  - Hard soldering in manufacture of electronic equipment
- **Semiconductor Industry**
  - Transport gas for diffusion processes
  - Reactant gas with oxygen to generate water vapor for wet oxidation
- **Power Stations**
  - For cooling generators, motors and frequency converters
- **Hydrogenation of oils and greases**
  - Delays oxidation
- **Metal Processing- Ferrous Metals**
  - Increased ductility
  - Higher yield point
- **Metal Processing – Non-ferrous metals**
  - Annealing of copper and copper alloys
  - Production of magnesium by electrolysis
- **Welding and Cutting**
  - Plasma cutting and welding
  - Soldering and welding in a protective atmosphere
- **Glass/ Quartz**
  - Fuel gas with oxygen for cutting and melting of quartz
- **Petroleum Industry**
  - Desulfurize and hydrocrack crude oil fractions
- **Transportation**
  - Fuel cells
  - Internal combustion engines

A key factor in hydrogen marketing is the distribution options. Table 20.7-3 lists the common hydrogen shipping methods. As can be seen from a comparison of the distribution options and the potential NGNP hydrogen production capacities (Table 20.7-1 NGNP Gas Production Rates), tube trailers or liquid hydrogen would be required for the smallest practical hydrogen plants for either the S-I or HyS processes. The HTSE smallest practical plant or the S-I or HyS commercial train would have to fill 2 to 3 liquid hydrogen tankers simultaneously for 24 hours every day. If shipping took place for only 12 hours, then the number of tankers would double and the storage capacity for liquid hydrogen would have to be at least 126 m^3 (or 33,000 gallons). Production from the smallest practical hydrogen plants for HyS or S-I would stretch the capability of tube trailer shipping.

Table 20.7-3 Distribution Options for Hydrogen

- **Pipeline (necessary for full plant : 4 trains)**
  - 0.5 to over 100 million SCFD
  - Depends upon pipeline availability
- **Liquid (choice for commercial train)**
  - About 1 million SCFD
  - Requires extra purification and liquefaction
- **Tube trailer (choice for smallest required hydrogen plant)**
  - Up to about 400,000 SCFD
- **Cylinders**
  - Up to about 100,000 SCFD

A 250 mile radius is the accepted economic transportation range of compressed hydrogen gas. Figure 20.7-11 shows the geographic area encompassed by a 250 mile radius drawn from the proposed INL site. Six companies were identified within this area that use bulk compressed hydrogen. All of these companies carry out metals processing operations. Their combined annual consumption is less than 200,000 Standard Cubic Feet per *Year*. The smallest practical hydrogen plant for the NGNP will produce over 700,000 Standard Cubic Feet per *Day*. There are three refineries, no float glass producers and no chemical producers that use hydrogen within this area.

The economic shipping radius is 1000 miles for liquid hydrogen. Consequently the potential market would expand. Even with this expansion, the demand for liquid hydrogen is low in comparison to the potential NGNP hydrogen plant production. The total North American capacity for liquid hydrogen is 89 million SCFD and about 1/3 of that capacity is idle. Liquid hydrogen use is expected to grow at the same rate as the GDP, about 2 ½ to 3% per year. A commercial train installed at the NGNP using the HyS process would displace about 12% of the current liquid hydrogen market. Hydrogen to be liquefied must be purified to a very high degree to avoid fouling of the liquefaction equipment. Hydrogen produced for fuel cell use must be similarly purified. The additional cost of purification and liquefaction is about $1.50 per kilogram.[20] The entry of NGNP-produced hydrogen into the Western U.S and Canada would disrupt this market in the future, without an expansion in demand. The interest in hydrogen for the NGNP project is primarily to stimulate growth in the hydrogen economy. It would therefore be appropriate to use the NGNP hydrogen production to fuel a fleet of hydrogen-powered vehicles. This is a market that is non-existent today, but the NGNP hydrogen plant could encourage its emergence. A kilogram of hydrogen has a heat of combustion equivalent to a gallon of gasoline and about 10% less than a gallon of diesel fuel. The U.S. Climate Change Technology Program target for urban buses is 10 miles per gallon gasoline equivalent.[21] If buses powered by hydrogen were to average 15 miles per hour in urban traffic and run 16 hours per day, the output from the smallest practical NGNP hydrogen plant with the HyS process could support a fleet of approximately 70 buses. A commercial train sized plant could support 700 buses. Similar alternative transportation opportunities should be studied and developed.

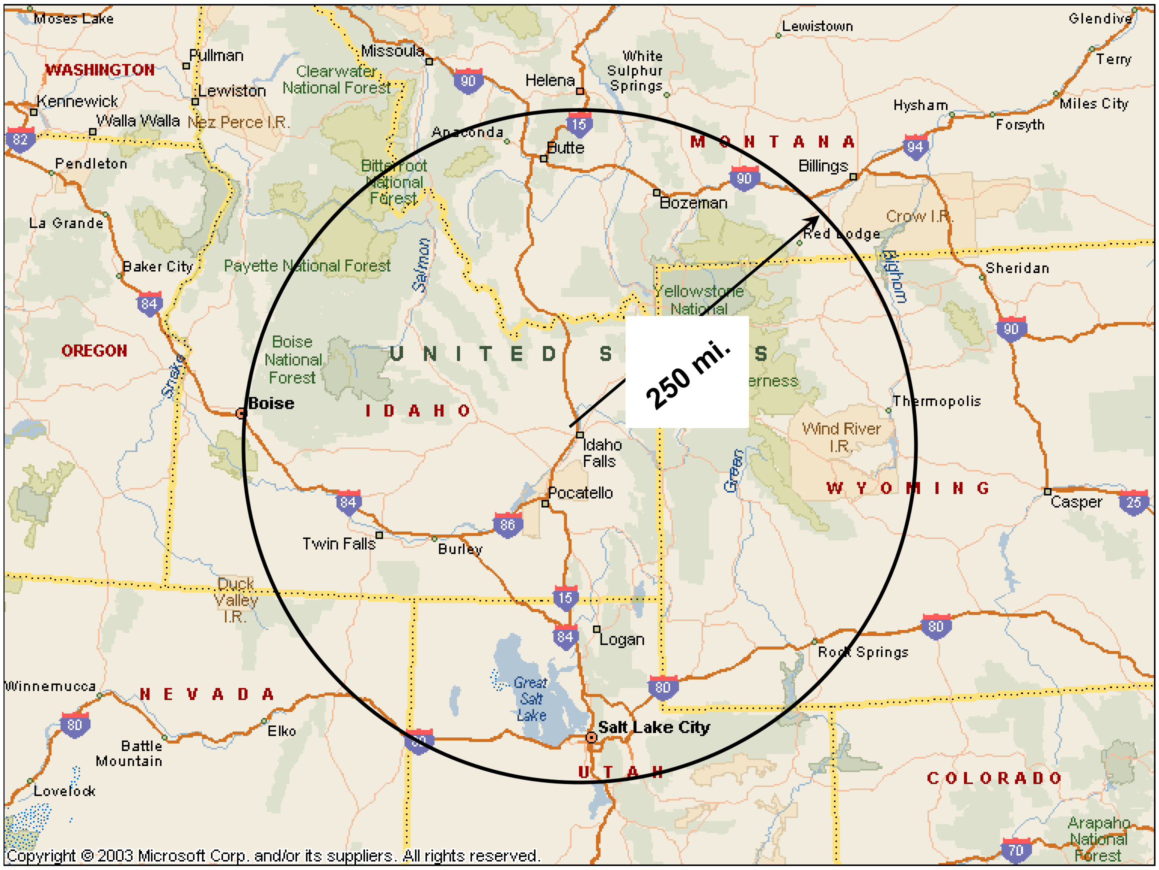

Figure 20.7-11 Economic Shipping Distance for Tube Trailer Hydrogen

An alternative consideration is to include a coal-to-liquid and/or coal-to-methane demonstration element to the NGNP mission as a second phase of further development. The Big Horn coal deposits in the vicinity of Hot Springs, Wyoming could become a feedstock source. There are active coal mines in this area. Coal conversion through the gasification to syngas and either Fischer-Tropsch technology for liquids or methanation for Substitute Natural Gas (SNG) would be a substantial market for both oxygen and hydrogen. Direct coal liquefaction would not use by-product oxygen. A gasification and syngas-based coal-to-liquids plant using all the hydrogen from a 50 MWth water-splitting plant would produce about 5000 barrels per day of liquid fuels. About half of the by-product oxygen would be used. A similarly based SNG plant would produce about 2.4 million SCFD of SNG. Without a local market for hydrogen, the NGNP by-products would have to be liquefied to be exported. Construction of a pipeline for these quantities of gas would not be practical.

For now, the market and price for hydrogen from an NGNP demonstration Hydrogen Plant is uncertain. As a conservative basis for the by-product revenue projection, the hydrogen price from comparably sized conventional SMR plant is suggested. For a levelized natural gas price of $7.5/MMBtu for the time period of interest and assuming no CO_2 penalties, the prices range from $1.65/ kg for a large capacity plant to about $1.80/kg for a plant comparably sized to the NGNP commercial train-based plant. For the latter, and using the same capacity factor logic as presented for the power revenues, namely 85% for the long-term and 75% for the first six years, the resultant revenues would be $11 million per year long-term and $9.5 million per year average for the first six years.

20.7.2.3 Oxygen

Oxygen is the major by-product of the water-splitting technologies. Oxygen applications most common in the area surrounding the INL site are: Oxy-fuel cutting, combustion enrichment for glass and ore smelting, and breathing oxygen. The usage rates for most of these are small in comparison to the potential NGNP hydrogen plant production. Some local larger oxygen users are Melaleuca, Inc. (chemical processing), Montana Resources, Advanced Silicon Materials LLC, and Thompson Creek Mining Company (all metals and minerals).

Oxy-fuel cutting is the most common application of high-pressure cylinder packaging quantities of oxygen. INL itself may be the largest market in the area for these oxygen gas cylinders. Because producing oxygen from air is a relatively low cost operation, most moderate size, low purity applications are served by on-site vacuum-swing adsorption units. The larger quantities associated with ore-smelting and mining combustion enrichment needs are usually served by on-site adsorption or cryogenic air separation systems. The high purity requirements for breathing oxygen are almost exclusively supplied by liquid oxygen tanks filled from centrally-located large scale cryogenic air separation plants.

The economical shipping radius for compressed or liquefied oxygen gas is about 150 miles. Most of the applications outside the INL site are associated with mining. There is also potential welding gas and breathing oxygen markets around Salt Lake City, Utah. These are just outside the economic shipping distance. The opportunities for marketing the oxygen by-product from the NGNP hydrogen plant are therefore limited and would depend upon expansion of local mining operations or displacement of existing air separation capacity. Air separation produces a nitrogen by-product which is also used by many of these operations. Bulk oxygen currently costs approximately $0.04 per kg and the price varies with the local cost of electricity. Provided that INL does not use the produced oxygen for its own needs, and if a market could be found, revenue of approximately $0.8 million per year might be generated.

20.7.3 PRODUCT REQUIREMENTS AND PURIFICATION NEEDS

20.7.3.1 Hydrogen

Post-production purification of the hydrogen required by any of these markets will be an important requirement. For the high temperature steam electrolysis process, steps for removal of sulfur and halogen compounds are not necessary. Water must be removed and some adsorption will be required.

In the HyS process, the hydrogen is generated out of a sulfuric acid electrolysis bath. The vapor pressures of both sulfuric acid and sulfur trioxide at the operating conditions of these baths are very low. Some sulfur dioxide will be stripped out of the electrolyzer bath, however. Sulfur dioxide in the gas phase must be removed to very low levels. Both scrubbing with caustic and adsorption will be required. Scrubbing will also guard against carry over of droplets during process upsets.

Table 20.7-4 Hydrogen Purity Requirements

	Application		
	Surface vehicle fuel cell	**Glass, Chemicals**	**Refining**
Purity Requirement (Mol %)	>99.99	>99.995	>99.90
Contaminant (max ppmv)			
Total non-H_2 or particulates	100	50	1000
Total hydrocarbons	2	1	N/A
Oxygen	5	1	1
Inerts (He, N_2, Ar)	60	2	<1000
Carbon oxides	1	1	10
Total Sulfur	0.004	5	5
Formaldehyde	0.01	N/A	N/A
Formic Acid	0.2	N/A	N/A
Ammonia	0.1	N/A	1
Total halogenates	0.05	N/A	1
Water	5	1.5	10
Particulates	$<10^{-3}$ mm @10^{-6} g/l	N/A	N/A

In the S-I process, the hydrogen is generated by the decomposition of hydrogen iodide. The vapor pressure of both iodine and hydrogen iodide are considerably higher than that of the sulfur species in the HyS process. The vapor pressure of hydrogen iodide is quite high, even at 25°C and it is moderately soluble in water. Therefore, there will probably be traces of hydrogen iodide in the product hydrogen even after the water scrubber shown on the flowsheet.[22] The purification section should include a caustic scrub to continue to remove iodine species and guard against any carryover of liquid droplets during upsets. This should be followed by a consumable adsorbent bed such as alumina or activated carbon. The total iodine in the product hydrogen would then be reduced to less than 1 parts per million by volume (ppmv).

For all processes, the final step may require an additional thermal swing drying step to lower the water content to less than 5 ppmv. The purity requirements of some markets are listed in Table 20.7-4.

Considerable purification would be needed to market oxygen from the thermo-chemical processes. Oxygen purity specifications do not explicitly address levels of sulfur dioxide because this compound is not involved in current commercial processes for producing oxygen. However, sulfur dioxide contamination will be an issue. Sulfur dioxide contaminating the oxygen would probably have to be removed to less than 1 ppmv. The low sulfur dioxide requirement for the welding gas cylinders is not related to the actual oxy-fuel cutting process. It comes from the potential use of the gas indoors where the end user may be exposed to the products of the combustion process. Breathing oxygen specifications should allow virtually no sulfur dioxide in the product because of its toxicity. Additionally, the “No Odor” requirement and the “others by infrared” require sulfur dioxide concentrations to be less than 0.1 ppmv. Furthermore, production of liquid oxygen will not tolerate either sulfur dioxide or water because it will condense and freeze during the liquefaction process, clogging the equipment.

Removing the sulfur dioxide from the product oxygen would require a caustic scrub followed by a consumable adsorbent bed.

Table 20.7-5 lists the purity requirements for the various market segments for compressed and liquefied oxygen.

Table 20.7-5 Oxygen Purity Requirements

	Application		
	Oxy-fuel cutting	**Combustion Enhancement**	**Breathing**
Required Purity (Mol %)	>99.5	>99	>99
Contaminant			
Total hydrocarbons	N/A	<0.5 ppmv	<50 ppmv
Inerts (N_2, Ar)	<0.4%	<1%	<1%
Carbon Dioxide			<300 ppmv
Carbon Monoxide			<10 ppmv
Total Sulfur Total Halogenates (Br, Cl, F, I)			No Odor
Solvents			<0.1
Others by Infrared			<0.1
Water	<50 ppmv	<50 ppmv	<6.6 ppmv (liquid)

20.7.4 NGNP BY-PRODUCTS, WASTE STREAMS AND EMISSIONS AND THEIR DISPOSAL

Daily operations at any facility will generate both liquid and solid waste streams requiring onsite treatment and disposal or offsite disposal, as the case may be. This section attempts to identify all anticipated waste streams associated with the nuclear reactor and the various hydrogen production technologies, as well as waste streams common to all the technologies. Specifically, waste streams are identified and discussed for the feed water treatment systems, water splitting technology options and non-process wastes such as solid wastes, sanitary wastes, oily wastes and contaminated storm water.

20.7.4.1 NGNP Reactor Wastes and Emissions

Tritium

There are three sources of tritium in the helium coolant. The chief source is the activation product from the small fraction of helium atoms in the coolant that are He^3. The second source is activation products from impurities and control material such as Li^6 and B^{10}. Ternary fission may is a third source, but the product remains almost entirely in the fuel particles.

Tritium is removed from the coolant by the Helium Purification System (HPS) in the form of tritiated water. This waste can be stored or discharged to the environment at concentrations below the allowable limits. Leakage to the atmosphere and permeation to the secondary coolant and process fluids can be limited by appropriate design of the penetrations, seals and the Helium Purification System.

Estimation of tritium production for the NGNP is based upon extrapolation from THTR operating data. In that plant the annual discharge was 91Ci, whereas the limit was 1000 Ci per year. The tritium level in the coolant remained constant which indicates that the production rate was equal to the discharge rate. Tritium production from activation of He^3 is proportional to the reactor power due to higher thermal flux in the core and the primary coolant density due to the higher probability of He^3 activation. Based on a 500 MWth PBMR with a 9 MPa coolant pressure, the tritium production from He^3 is estimated to be approximately 115 Ci per year.

Table 20.7-6 Volume of Core Components to Waste for a PBMR NGNP

<table>
<tr><th>Component</th><th colspan="2">Primary Radioactivity Sources</th><th>No. Units in Reactor</th><th>Frequency of Removal</th><th>Number Units Removed</th><th>Volume per Unit, m³</th><th>Volume per Year, Avg m³</th><th>Volume over 40 years, EOL, m³</th></tr>
<tr><td>Fuel Elements, whole</td><td colspan="2">All fission products and activated products</td><td>~451000</td><td>daily</td><td>[610]</td><td>1.13E-4</td><td>[25]</td><td>[910]</td></tr>
<tr><td rowspan="5">Replaceable Outer Side Reflectors</td><td>Nuclide</td><td>Half-life, Yr</td><td rowspan="5">[1080]</td><td rowspan="5">18 years</td><td rowspan="5">[1080]</td><td rowspan="5">TBD</td><td rowspan="5"></td><td rowspan="5">[56.3]</td></tr>
<tr><td>C-14</td><td>5700</td></tr>
<tr><td>Sr-90</td><td>29</td></tr>
<tr><td>Ag-110m</td><td>0.7</td></tr>
<tr><td>Cs-137</td><td>30</td></tr>
<tr><td>Replaceable Inner Reflectors</td><td colspan="2">Same as side reflectors</td><td>[400]</td><td>18 Years</td><td>[400]</td><td>TBD</td><td></td><td>[22]</td></tr>
<tr><td>Replaceable Top Reflectors</td><td colspan="2">Same as side reflectors</td><td>TBD</td><td>18 years</td><td>TBD</td><td>TBD</td><td>TBD</td><td>TBD</td></tr>
<tr><td>Operating Control Rods</td><td colspan="2">Activated Incoloy and B_4C</td><td>24</td><td>[6 years]</td><td>[6]</td><td>[0.05]</td><td>[0.05]</td><td>[1.8]</td></tr>
</table>

Table 20.7-6 above, provides a summary of the estimated radioactive waste material that may be produced by a PBMR-based NGNP. The assumptions used in the preparation of this estimate are as follows:

1. Reactor life is 40 years with 90% availability
2. The replaceable outer side reflector is 0.4m thick and the total height is 10.92 m
3. The replaceable inner reflector is also 0.4m thick with the same height as the outer reflector.
4. The top replaceable reflector is 1.2 m thick (this probably will not need replacement)
5. The control rods are 0.1m in diameter and 6.5m long.
6. The replacement schedule for the control rods will be approximately every 6 years
7. Fuel sphere replacement rate is 610 per day
8. The estimate does not include the end-of-life disposal of fuel or internals.

20.7.4.2 Feedwater Treatment

At this time, feedwater source quality is not known. Municipally supplied potable water may not be available, whether due to proximity issues to the municipal distribution system due to the location of the project site or due to supply inadequacies. Water may therefore be groundwater or river water. Water purity for any of the three processes under consideration has not been identified and there has been insufficient research and development done in this area to determine the affect of dissolved solids on any of the processes or their components. Undoubtedly, very pure water with low suspended and dissolved solids will be required.

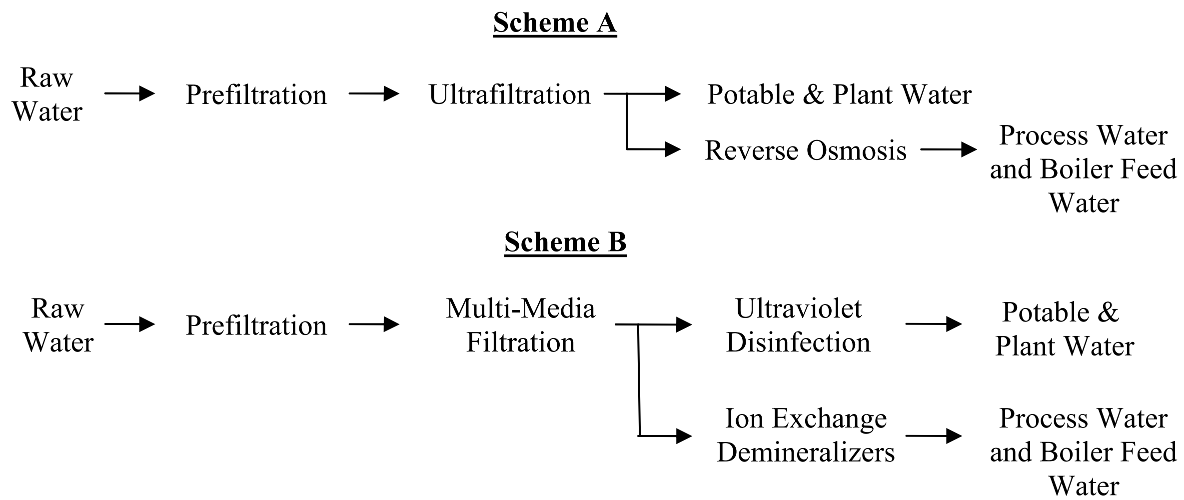

Figure 20.7-12 Hydrogen Plant Water Treatment Schemes

Several different technologies, or combinations of technologies, are available to meet the anticipated process water purity requirements. The final scheme for the feed water system can be chosen once feedwater quality and purity requirements have been better defined. However, the feedwater system will most likely consist of one of the treatment process schemes shown in Figure 20.7-12 Hydrogen Plant Water Treatment Schemes, above.

The size of the feedwater treatment system from preliminary mass balances is approximately 150 gpm for the process. However, such factors as pump sealing requirements, boiler feed water, and other plant uses (i.e., site potable water and miscellaneous plant water use) may increase the required size of some of the components and systems.

Waste streams will vary depending on the technology used. All the technologies identified above, except for ultraviolet disinfection and ion exchange demineralizers, will produce a periodic backwash or continuous reject stream requiring treatment. An ion exchange system will require facilities for bulk chemical storage, for preparation of regenerant, and for neutralization of the regeneration waste streams.

Liquid waste, solid wastes and applicable disposal methods for each technology are identified in Table 20.7-7 below.

Table 20.7-7 Feedwater Treatment Wastes and Disposal Methods

Process Technology	Liquid Waste	Solid Waste	Disposal Method
PreFiltration	--	Screened Solids	Onsite or licensed waste hauler
Multi-Media Filtration	Backwash water & solids	Periodic media replacement over design life of system	*Liquid* – onsite wastewater treatment system *Solid* – licensed waste hauler
UltraFiltration	Backwash water & solids	Periodic media replacement over design life of system	*Liquid* – onsite wastewater treatment system *Solid* – licensed waste hauler
UltraViolet Disinfection	--	Periodic media replacement over design life of system	*Universal Waste* – licensed waste hauler
Reverse Osmosis	Reject Water, Membrane Cleaning Wastes	Prefilters and membranes	*Liquid* – onsite neutralization & wastewater treatment system *Solid* – licensed waste hauler
Ion Exchange Demineralizers	Regeneration Wastes	Periodic resin replacement over design life of system	*Liquid* – onsite neutralization system *Solid* – resin supplier or licensed waste hauler

Resin suppliers may offer contract services to test, replace and dispose of spent ion exchange resins. The appropriate strategy for resin disposal will need to be investigated during subsequent design phases.

20.7.4.3 Water Splitting Process Waste Streams

Liquid Waste Streams

Each of the technologies requires feedwater makeup to replace water that is converted into hydrogen and oxygen by the process. Although there is a net loss of water, water is lost as a gas and any dissolved solids or other corrosion products in the water will remain in the process and continue to increase in concentration until purged from the system. Periodic blowdowns will be required to reduce the concentration of these dissolved solids. Onsite treatment, such as chemical precipitation, will be required to remove the metal contaminants prior to discharge of the liquid waste streams. Further research and development will be required to determine the allowable cycles of concentration within each process before a process blowdown is required.

Furthermore, all three technologies may utilize closed loop cooling systems to cool the process liquid and power generation waste heat. These closed loop cooling systems will utilize cooling towers and will require periodic blowdown to reduce dissolved solids and corrosion products concentration in the cooling water.

Due to heat and corrosion considerations, mechanical seals for the various pump applications will most likely require pressurized seal water systems to cool and flush the seals thereby increasing the life of the seals. Water purity requirements for this seal water are not known at this time. Further research and development will need to be done to determine the most appropriate pump sealing system. Regardless, seal cooling and flushing water will need to be treated appropriately.

The oxygen and hydrogen product will require further processing to meet purity requirements. This processing will require caustic scrubbing to remove residual sulfur compounds and sulfuric acid mist. Neutralization of the spent caustic stream will be required. Oxygen production from the smallest practical hydrogen plant would be about 13,600 kg per day. Removing the bulk of the 5% sulfur dioxide would produce about 1400 kg/day of $NaHSO_4$, or about 470 tonnes/year of $NaHSO_4$ in a dilute water solution from the scrubbing step and consume about 470 lb/day of NaOH. Additionally, about 45,000 kg/year of adsorbent would be consumed to remove the final 100 ppmv of sulfur dioxide from the oxygen product.

Routine maintenance operations will occasionally require vessels or pumps to be taken offline and drained. Drained liquids may be acidic or basic and require neutralization treatment.

The S-I process has additional associated waste handling and disposal concerns. Bulk iodine will be required to replenish iodine lost in the process and may require additional chemical processing systems to meet purity requirements. At this time, iodine purity is not identified and will need to be addressed in subsequent research and development. Regardless, appropriate waste treatment technologies will need to be used to treat potential liquid waste streams associated with the chosen processing systems.

In addition, extractive distillation with phosphoric acid may be used in the sulfur-iodine process. Typical treatment of phosphoric acid waste streams includes neutralization, followed by the addition of chemical coagulants (e.g., polyaluminum chloride). Careful consideration should be given to the handling and treatment of phosphoric acid wastes.

Solid Waste Streams

It is inevitable that equipment and components will wear out and degrade over the design life of the facility. These components will need to be replaced as part of an ongoing maintenance plan. The following components are identified as requiring periodic replacement, whether due to reduction in performance from scaling or material corrosion and degradation:

- SO_2 absorber packing
- Spent electrolyzer cells and membranes (HTSE and HYS Processes)
- Spent catalysts
- Heat exchanger tubes

Table 20.7-8 Summary of Water-Splitting Process Wastes

Process Technology	Liquid Waste	Solid Waste	Disposal Method
All Technologies	Feed Water Treatment Waste Process Blowdown Cooling System Blowdown Pump Seal Water Purge & Drain from Maintenance Operations	Spent ion exchange resins or reverse osmosis membranes Used equipment	*Liquid* – onsite wastewater treatment system *Solid* – scrap dealers, municipal solid waste, ion exchange resin and membrane manufacturers (recycle)
High Temperature Electrolysis	--	Spent electrolyzer anodes and cathodes	*Solid* – Licensed Waste Hauler (with hazardous waste disposal permit)
Hybrid Sulfur	Spent Caustic from Gas Purification --	Spent electrolyzer anodes and cathodes SO_2 absorber packing	Licensed Waste Hauler or Media supplier Recovery specialist for platinum on electrodes
Sulfur Iodine	Liquid wastes from iodine processing Spent Caustic from gas purification Phosphoric Acid Waste from Distillation	Spent activated carbon from iodine processing and ventilation scrubbers SO_2 absorber packing	*Liquid* – onsite waste processing system *Solid* – Licensed Waste Hauler or Media supplier

Solid waste generated by all processes will include activated carbon used for the purification of the product gas streams, as required. Activated carbon may be disposed by a licensed waste hauler, or returned to the carbon supplier for regeneration or disposal.

Considering the chemical characteristics and toxicity of iodine, additional activated carbon disposal will be required for spent carbon from scrubbers for any iodine processing area ventilation systems.

Liquid waste, solid wastes and disposal methods for all including individual water splitting technologies are summarized in below

20.7.4.4 Other Plant Non-Process Waste Streams

Solid Waste

The State of Idaho requires industrial, commercial and utility waste generators to track the volume of wastes generated, determine whether or not each is classified as a hazardous, universal or mixed waste and ensure that all wastes are properly disposed of according to federal, state and local requirements. Any new facility will be required to develop plans for the proper identification and storage of hazardous and universal waste. These wastes will need disposal by the appropriate licensed waste haulers.

Storm Water

Storm water runoff will be generated at the facility and appropriate mitigation measures and treatment will need to be identified and implemented. A Storm Water Pollution Prevention Plan will be required to be developed and implemented. Runoff volumes and peak discharge rates can not be developed until a final site layout is determined for the facility.

Oily Wastes

Storm water and building drains in maintenance, shipping/receiving and parking areas may be contaminated with oil. Appropriately designed oil/water separation systems will be required to treat these waste streams. The facility will need to contract with a licensed waste hauler to remove the oily waste.

Sanitary Wastes

Sanitary wastes may either be treated onsite with a packaged treatment system or discharged to a publicly owned treatment system, if available. Discharge to a publicly owned system may necessitate installation of a pump station and force main to transfer the sanitary waste to the collection system. In addition, the sanitary discharge will need to meet the local sewer discharge requirements and may have additional effluent restrictions if any process wastewater is discharged to the sewer. Local authorities can implement local discharge limitations for industrial or commercial users. These limits typically include limits on metals, such as iron, copper and mercury, as well as other toxic pollutants. Additional pre-treatment at the facility may be required.

20.7.5 RECOMMENDATIONS

Recommendation 1: Size of the NGNP Hydrogen Plant

The recommended size of the reference NGNP Hydrogen Plant commercial demonstration is based on a Decomposition Reactor with a thermal duty of $50MW_{th}$. Only a plant of at least this size will fully demonstrate this technology commercially. A retreat from this size should be made only if disposing of the hydrogen product becomes an overriding factor.

Demonstration of the HTSE process with a 50 MW_{th} process-coupling heat exchanger will produce as much as half of the hydrogen as is sold as a liquid in the United States today. It should be demonstrated with a 13 MW_{th} PCHX.

Recommendation 2: Develop a Market for the Product Hydrogen

Currently, there is no easily accessible market for hydrogen produced by the NGNP Hydrogen Plant. As part of the demonstration, development of a local transportation system using buses and other vehicles using hydrogen as an internal combustion engine fuel should be investigated actively. In addition, consideration is warranted for a later coal-to-liquids demonstration element of the NGNP Project. Disposal of the product hydrogen from this plant will be an important consideration whatever the size of the plant. Once a market is identified and the requirements are clear, a purity specification for the hydrogen product can be developed.

Recommendation 3: Conceptual Design of Purification and Waste Disposal

Feed pre-treatment, product purification, waste treatment and disposal are frequently ignored until late in the development of a demonstration project. The effect of these factors on the cost and on the design of the main production unit itself can be important. These elements should be included explicitly in the conceptual design of the NGNP Hydrogen Plant. To do this successfully the purity specification for the hydrogen product is required.

Recommendation 4: Progressing the Design of the NGNP Hydrogen Plant

Begin to develop clear Design Data Needs by choosing a preferred technology for the NGNP Hydrogen Plant by the beginning of the NGNP Conceptual Design Phase. Advance the decision point for choosing the water-splitting technology and progress that technology by developing a process design including the aspects described in Recommendation 3 as part of the NGNP Conceptual Design Phase. This effort will further focus the research and development effort.

Recommendation 5: Technology Development

See the section on Technology Development, below.

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DEFINITIONS

Adsorbent	Solid substance used to condense gases, liquids or dissolved substances on its surface.
Bunsen Reaction	A reaction of water, sulfur dioxide and iodine to form iodic acid and sulfuric acid
Catalyst	A substance that accelerates the rate of a chemical reaction but remains unchanged afterwards
Ceramic	Any of various hard, brittle, heat-resistant and corrosion-resistant materials
Chemical Equilibria/Equilibrium	When the net change of reactants and products in a chemical reaction is zero.
Chemical Precipitation	In water or wastewater treatment, the addition of chemicals (e.g., lime, caustic soda or ferric chloride) to remove dissolved metals or soluble organic contaminants.
Critical Equipment	The piece of equipment that limits the maximum capacity of the train and that is expected to pose a challenge with respect to one or more of the demonstration criteria.
Decomposition	A reaction in which a single compound reacts to give two or more substances
Demineralizer	In water treatment, a substance or system used to remove minerals or mineral salts from a liquid
Electrochemical	Pertaining to the interaction or interconversion of electric and chemical phenomena
Electrolysis	The passage of a direct electric current through an ion-containing solution. Electrolysis produces chemical changes at the electrodes.
Enthalpy	A thermodynamic quantity that is equal to the sum of the internal energy of a system plus the product of the pressure-volume work done on the system.
Equivalent Hydraulic Diameter	Equal to (4 x axial flow area ÷ wetted perimeter)
Extractive Distillation	The extraction of the volatile components of a mixture by the condensation and collection of the vapors that are produced as the mixture is heated
Fluidized Bed Reactor	A reactor in which a bed of small solid particles is suspended and kept in motion by an upward flow of a fluid or gas.
Friction Factor	A dimensionless number used in studying fluid friction in pipes, equal to the pipe diameter times the drop in

	pressure in the fluid due to friction as it passes through the pipe, divided by the product of the pipe length and the kinetic energy of the fluid per unit volume
Halogen	Any of a group of five chemically related nonmetallic elements including fluorine, chlorine, bromine, iodine, and astatine
Hazardous Waste	Per Idaho Statute 39-4403, a waste or combination of wastes of a solid, liquid, semisolid, or contained gaseous form which, because of its quantity, concentration or characteristics (physical, chemical or biological) may: (a) Cause or significantly contribute to an increase in deaths or an increase in serious, irreversible or incapacitating reversible illnesses; or (b) Pose a substantial threat to human health or to the environment if improperly treated, stored, disposed of, or managed. Such wastes include, but are not limited to, materials which are toxic, corrosive, ignitible, or reactive, or materials which may have mutagenic, teratogenic, or carcinogenic properties but do not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to national pollution discharge elimination system permits under the federal water pollution control act, as amended, 33 U.S.C., section 1251 et seq., or source, special nuclear, or byproduct material as defined by the atomic energy act of 1954, as amended, 42 U.S.C., section 2011 et seq
Heat Exchanger	A device in which energy is transferred from one fluid to another across a solid metallic or ceramic surface.
Heat Transfer Coefficient	A constant that represents how easily heat can move.
Inert	Not readily reactive with other elements; forming few or no chemical compounds.
Light Hydrocarbon	Hydrocarbons up to a molecular weight of about 72
Mixed Waste	Solid waste that contains both hazardous and radioactive waste.
Multimedia Filtration	In water treatment, a process that uses multiple types of filtering media to remove solids greater than 10 microns in size.
Osmotic Pressure	The hydrostatic pressure produced by a solution in a space divided by a differentially permeable membrane due to a differential in the concentrations of solute
Purity	Relating to the absence of other chemical compounds or chemical species.

Reaction Kinetics	The rate of a chemical reaction.
Reactive Distillation	A unit operation combining both a chemical reaction and distillation. Typically, reactants are fed continuously to a distillation column in which the reaction takes place. Reactants are simultaneously separated from the products thereby allowing the reaction to proceed.
Recuperator	A heat exchanger that helps boost the efficiency of a process. The recuperator passes some of the heat of the product gas back to the process as it comes through the exchanger.
Reverse Osmosis	The process of forcing a solvent from a region of high solute concentration through a membrane to a region of low solute concentration by applying a pressure in excess of the osmotic pressure.
Scalability	The ability to increase process production rates without significant changes to reaction kinetics or transport phenomena.
Scrubber	An air pollution control device that uses a high energy liquid spray to remove aerosol and gaseous pollutants from a gas stream. The gases are removed either by absorption or chemical reaction
Steam Reformer	A piece of equipment that carries out the endothermic steam reforming reaction, that is, reacting
Thermochemical	Relating to the chemistry of heat and heat-associated chemical phenomena.
Train	Refers to a collection of equipment or components that form a functional process group.
Transport Phenomena	Any of various mechanisms by which particles or quantities move from one place to another. There are three main types of transport phenomena: heat transfer, mass transfer, and fluid dynamics (or momentum transfer).
Tritium	Common name for hydrogen-3 (^3H), which is a radioactive isotope of hydrogen.
Tritiated Water	Liquid formed with tritium combines with oxygen.
Tube Trailer	Tractor trailer with permanently attached large high pressure cylinders.
Ultrafiltration	A variety of membrane filtration in which hydrostatic pressure forces a liquid against a semi-permeable membrane. Suspended solids and solutes of high molecular weight are retained, while water and low molecular weight solutes pass through the membrane.
Ultra Violet Disinfection	In water and wastewater treatment, the destruction of bacteria, viruses and pathogens by using light in the

	ultraviolet spectrum (i.e., 254 nm)
Universal Waste	Per Idaho Universal Waste Rule, Universal Wastes are defined certain commonly generated hazardous wastes. Specifically, a hazardous waste exhibiting any of the following characteristics can be classified as a universal waste: (a) The waste is frequently generated in a wide variety of settings (other than industrial settings usually associated with hazardous wastes). (b) The waste is generated in a vast community and in sufficient quantities to cause difficulties in managing the waste properly for both the regulated community and the regulators. (c) The waste is present in significant volumes in the municipal solid waste stream (non-hazardous waste management systems). Wastes identified in Idaho as universal wastes include batteries, agricultural pesticides, thermostats, spent lamps containing mercury or lead and mercury containing items.
Upset	Relating to a disruption in a process that affects efficiency or operation.
Water Splitting	Carrying out the net reaction that decomposes water into its constituent elements.

REQUIREMENTS

There are no requirements generated by this special study.

LIST OF ASSUMPTIONS

Hydrogen Plant

Heat is supplied to the hydrogen plant at its battery limits at 900°C in the form of hot helium and is returned to the heat transport system.

The heat transport medium is carried in a secondary loop and therefore does not pass through the core of the PBMR.

The heat and material balances produced in earlier reports for the three H_2 production technologies examined are reasonable estimates of the demonstration plant performance.

VLE, thermo-chemical, and transport property estimates for the various species at these high temperatures and pressures are accurate.

Performance property estimates for the solid oxide separation materials in the electrolyzers and decomposers, namely permeation rate, energy consumption, and potential leakage rate of the prototype devices are reasonable.

Hybrid Sulfur

The decomposer design proposed by Westinghouse assumes that the residence time is not controlling and heat transfer into the reaction zone is controlling.

The Westinghouse decomposer design assumes that the tube supplier will develop 10 m long tubes in time to build the demonstration plant.

Bulk caustic scrubbing will reduce the 5% SO_2 in the O_2 product to 100 ppmv.
The capacity of the adsorbent used to remove the remaining SO_2 is about 4.5 % SO_2 by mass.

Commercial H_2 production train size is set by the largest practical size of the Decomposition Reactor. (same assumption is made for the S-I process)

Commercial

Projected growth of hydrogen and oxygen demand from traditional users in the region that can be served from the demonstration plant is equivalent to the growth in the North American GDP.

TECHNOLOGY DEVELOPMENT

High Temperature Steam Electrolysis

Technology development for the high-temperature electrolysis process should focus on the design and fabrication of the electrolyzer cell. The selection of the basic material for the electrolytic cells has been completed. The main focus of the development of these cells will be in scaling up both the size of the cells and the manufacturing process so that the thousands of cells can be reliably fabricated at a reasonable cost.

The impact of common impurities found in high temperature steam should be investigated. In testing the ILS unit steam should be generated and transported in vessels and piping fabricated from those materials expected to be used in the commercial plant. Furthermore commercial water treatment and boiler feedwater treatment should be used.

Design and testing of the seals on the cells that contain the feed steam and the O_2 and H_2 product will be critical. Prior to building the demonstration plant these seals should be demonstrated at the bench and pilot scale to show acceptable leakage rates at process conditions over long periods of time. Seal testing should also prove that they can withstand multiple start-up and shutdown cycles that include both pressure and thermal cycling from ambient up to operating conditions. Some of the development activity could leverage from other development programs supporting equipment using metal oxide membrane technology.

Another area of technology development for the HTSE process is the large heat exchangers in various services. The first effort should be to perform a temperature-enthalpy analysis of the entire system including the recuperators. A thermal design of these exchangers should be carried out by an experienced industrial heat transfer professional.

The high temperature and pressure of the process combined with the high H_2 or O_2 content in some of the streams make material selection and testing necessary. Thermal stresses, creep, H_2 embrittlement, and stress corrosion are all possible problems with these exchangers. It is unlikely that carbon steel or stainless steel can meet the needs of these heat exchanger designs. A program to test and evaluate the construction materials at small scale will likely be required. Following on basic material selection, design and fabrication method development will also be necessary.

A significant part of these technical programs will be evaluations of the cost to produce the critical components to ensure that the projected capital cost of any commercial facility is reasonable.

Sulfuric Acid Decomposition

A parallel development effort extending to the pilot scale is needed for the competing conceptual designs of the Decomposition Reactor. The conditions in this reactor are such that it is likely that only a ceramic material can be used for the heat transfer surfaces. Granting this, there are several issues faced by any design:

- Bonding and sealing ceramic to metal
- Catalyst life, replacement of catalyst or incorporating catalyst into the reactor
- Thermal design of the piece of equipment
- Developing a design that can be fabricated.

A search for all work being carried out world-wide should be made on the subject of ceramic to metal bonding and this work should be followed and actively supported.

Work on the decomposition reactor at Sandia, UNLV and Ceramatec should be supported and other work in Korea and Japan followed.

Thermal designs of each of the concepts as well as conceptual mechanical designs should be attempted by heat exchanger fabricators or other heat exchanger professionals.

Hybrid Sulfur

Verification of the thermodynamic, VLE, and transport properties of the mixtures expected within the HyS process is needed. The current estimates of these properties are based on extrapolation of experimental data.

There is a need to determine the effect of impurities in the feedwater and make-up acid on the performance of the decomposition catalyst and the electrolyzers.

Work at Savannah River National Laboratory on the electrolyzer should be supported. This work includes finding a separation membrane for the cells, optimizing catalyst loading on the electrodes and otherwise optimizing the cell. Work is still required in scaling up these cells to a commercial size.

Sulfur-Iodine

The current process design is not based on a converged mass and energy balance. Adequate thermodynamic data must be gathered and a converged mass and energy balance developed. Efforts at solving other issues in this technology without a converged flowsheet simulation may be futile. An effort should be made to simplify the flowsheet significantly.

The flow scheme makes extensive use of expanders for both vapor and liquid streams to recovery energy within the process. An analysis of the process conditions against practical design limits for such rotating equipment is necessary to understand if the current process is viable or what changes are required.

Basic work is required in assessing the ability to separate the various species involved in the reactions. This depends not only on phase equilibrium data, but also on equipment design.

There is a need to determine the effect of impurities on the performance of the reactions and separations in this process.

The Decomposer Reactor design requires the same design evaluation, testing and development as described above for the HyS process. The Recuperator poses very similar design issues as the HTSE heat exchangers and will require a similar development program.

APPENDICES

APPENDIX A: HYBRID SULFUR MATERIAL BALANCE AND FLOWSHEET

APPENDIX B: ELECTRICITY PRICE DATA

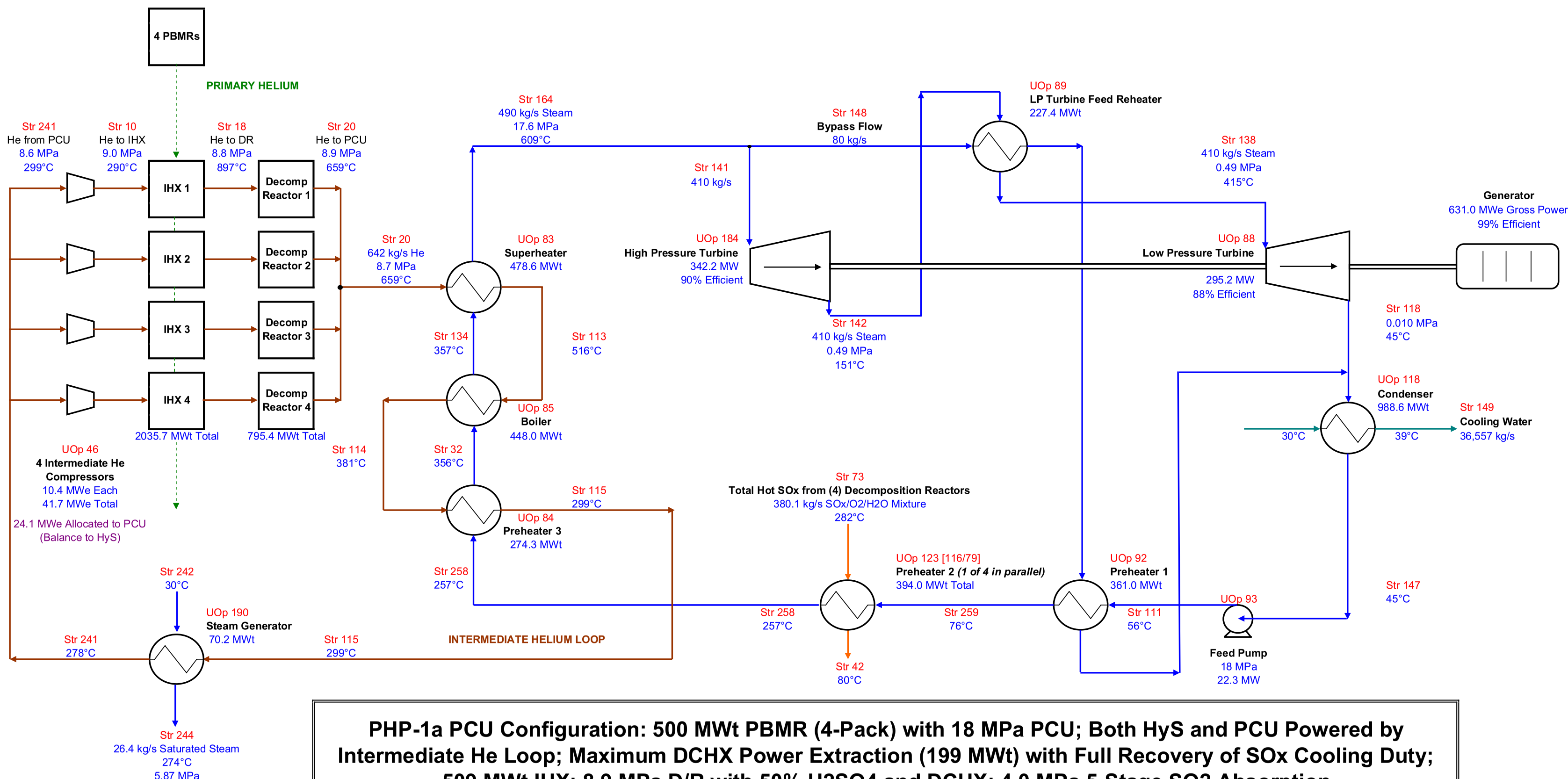
B-1: Electricity Price Data : Western Electric Coordinating Council, The Fifth Northwest Electric Power and Conservation Plan, 2005, Vol. 3, Appendix C: "Wholesale Electricity Price Forecast"

B-2: Excerpt from the Idaho Power Company 2006 Integrated Resource Plan

B-3: E-mail from Karl Bokenkamp of Idaho Power Company

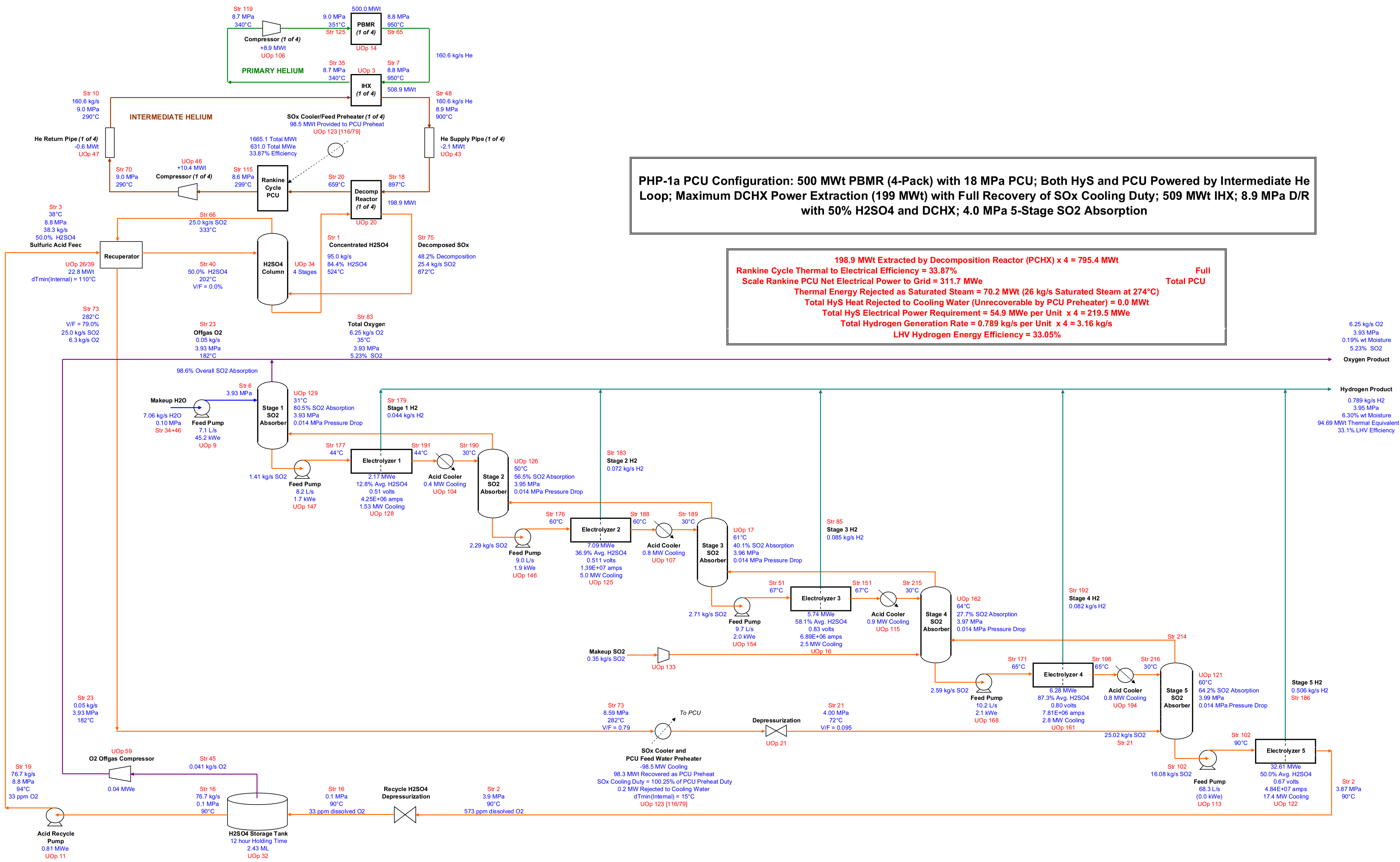
APPENDIX C: REVISED SLIDES FROM MEETING OF DECEMBER 6, 2006

APPENDIX A: SPECIAL STUDY 20.7, HYBRID SULFUR MATERIAL BALANCE AND FLOWSHEET



PHP-1a PCU Configuration: 500 MWt PBMR (4-Pack) with 18 MPa PCU; Both HyS and PCU Powered by Intermediate He Loop; Maximum DCHX Power Extraction (199 MWt) with Full Recovery of SOx Cooling Duty; 509 MWt IHX; 8.9 MPa D/R with 50% H2SO4 and DCHX; 4.0 MPa 5-Stage SO2 Absorption

198.9 MWt Extracted by Decomposition Reactor (PCHX) x 4 = 795.4 MWt
Rankine Cycle Thermal to Electrical Efficiency = 33.87%
Full Scale Rankine PCU Net Electrical Power to Grid = 311.7 MWe
Total PCU Thermal Energy Rejected as Saturated Steam = 70.2 MWt (26 kg/s Saturated Steam at 274°C)
Total HyS Heat Rejected to Cooling Water (Unrecoverable by PCU Preheater) = 0.0 MWt
Total HyS Electrical Power Requirement = 54.9 MWe per Unit x 4 = 219.5 MWe
Total Hydrogen Generation Rate = 0.789 kg/s per Unit x 4 = 3.16 kg/s
LHV Hydrogen Energy Efficiency = 33.05%



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Total Hydrogen Generation Rate = 0.789 kg/s per Unit x 4 = 3.16 kg/s
LHV Hydrogen Energy Efficiency = 33.05%
Full
Total PCU
PRIMARY HELIUM
INTERMEDIATE HELIUM
PBMR (1 of 4)
500.0 MWt
UOp 14
IHX (1 of 4)
UOp 3
508.9 MWt
Compressor (1 of 4)
+8.9 MWt
UOp 106
160.6 kg/s He
He Return Pipe (1 of 4)
-0.6 MWt
UOp 47
He Supply Pipe (1 of 4)
-2.1 MWt
UOp 43
SOx Cooler/Feed Preheater (1 of 4)
98.5 MWt Provided to PCU Preheat
UOp 123 [116/79]
Rankine Cycle PCU
1665.1 Total MWt
631.0 Total MWe
33.87% Efficiency
Compressor (1 of 4)
UOp 46
+10.4 MWt
Decomp Reactor (1 of 4)
UOp 20
198.9 MWt
Recuperator
UOp 26/39
22.8 MWt
dTmin(Internal) = 110°C
H2SO4 Column
UOp 34
4 Stages
Sulfuric Acid Feed
Concentrated H2SO4
Decomposed SOx
Offgas O2
Total Oxygen
Oxygen Product
Hydrogen Product
Makeup H2O
98.6% Overall SO2 Absorption
Stage 1 SO2 Absorber
Stage 2 SO2 Absorber
Stage 3 SO2 Absorber
Stage 4 SO2 Absorber
Stage 5 SO2 Absorber
Electrolyzer 1
Electrolyzer 2
Electrolyzer 3
Electrolyzer 4
Electrolyzer 5
Feed Pump
Acid Cooler
Makeup SO2
0.35 kg/s SO2
UOp 133
Depressurization
UOp 21
SOx Cooler and PCU Feed Water Preheater
-98.5 MW Cooling
98.3 MWt Recovered as PCU Preheat
SOx Cooling Duty = 100.25% of PCU Preheat Duty
0.2 MW Rejected to Cooling Water
dTmin(Internal) = 15°C
UOp 123 [116/79]
To PCU
O2 Offgas Compressor
UOp 59
0.04 MWe
H2SO4 Storage Tank
12 hour Holding Time
2.43 ML
UOp 32
Recycle H2SO4 Depressurization
Acid Recycle Pump
0.81 MWe
UOp 11

APPENDIX B: SPECIAL STUDY 20.7, ELECTRICITY PRICE DATA

B-1: ELECTRICITY PRICE DATA : WESTERN ELECTRIC COORDINATING COUNCIL, THE FIFTH NORTHWEST ELECTRIC POWER AND CONSERVATION PLAN, 2005, VOL. 3, APPENDIX C: “WHOLESALE ELECTRICITY PRICE FORECAST”

Wholesale Electricity Price Forecast

This appendix describes the wholesale electricity price forecast of the Fifth Northwest Power Plan. This forecast is an estimate of the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This price represents the marginal cost of electricity and is used by the Council in assessing the cost-effectiveness of conservation and new generating resource alternatives. The price forecast is also used to estimate the cost implications of policies affecting power system composition or operation. A forecast of the future Western Electricity Coordinating Council (WECC) generating resource mix is also produced, as a precursor to the electricity price forecast. This resource mix is used to forecast the fuel consumption and carbon dioxide (CO_2) production of the future power system.

The next section describes the base case forecast results and summarizes the underlying assumptions. The subsequent section describes the modeling approach. The final section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions. Costs and prices appearing in this appendix are in year 2000 dollars unless otherwise noted.

BASE CASE FORECAST

The base case wholesale electricity price forecast uses the Council's medium electricity sales forecast, medium fuel price forecast, average hydropower conditions, the new resource cost and performance characteristics developed for this plan, and the mean annual values of future CO_2 mitigation cost, renewable energy production tax credits and renewable energy credits of the portfolio analysis of this plan. These are summarized in Table C-1.

Table C-1: Summary of assumptions underlying the base case forecast

Hydropower	Average hydropower conditions Linear reduction of available Northwest hydropower by 450 MW 2005 through 2024
Fuel prices	5th Plan forecast, Medium case
Loads	5th Plan electricity sales forecast, Medium case, adjusted for 150 aMW/yr conservation, 200 aMW Direct Service Industry load and transmission and distribution losses
Northwest resources	Resources in service as of Q4 2004 Resources under construction as of Q4 2004 Retirements scheduled as of Q4 2004 75 percent of Oregon and Montana system benefit charge target acquisitions 50 percent of demand response potential by 2025
Other WECC resources	Resources in service as of Q1 2003 Resources under construction as of Q1 2003 Retirements scheduled as of Q1 2003 75 percent of state renewable portfolio standard and & system benefit charge target acquisitions 50 percent of demand response potential by 2025.

New resource options	610 MW natural gas-fired combined-cycle gas turbines 100 MW wind power plants - prime resource areas 100 MW wind power plants - secondary resource areas 400 MW coal-fired steam-electric plants 425 MW coal gasification combined-cycle plants 2x47 MW natural gas-fired simple-cycle gas turbines 100 MW central-station solar photovoltaic plants Montana First Megawatts 240 MW natural gas-fired combined-cycle plant Mint Farm 286 MW natural gas-fired combined-cycle plant Grays Harbor 640 MW natural gas-fired combined-cycle plant
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades as of Q1 2003
Carbon dioxide penalty	Washington & Oregon: \$0.87/ton CO_2 for 17% of production until exceeded by the mean annual values of the portfolio analysis. Other load-resource zones: The mean annual values of the portfolio analysis
Renewable resource incentives	Federal production tax credit at mean annual values of the portfolio analysis Green tag revenue at mean annual values of the portfolio analysis

The forecast Mid-Columbia trading hub price, levelized for the period 2005 through 2025 is \$36.20 per megawatt-hour. In Figure C-1, the current forecast is compared to the base case ("Current Trends") forecast of the Draft 5th Power Plan (levelized value of \$36.10 per megawatt-hour).

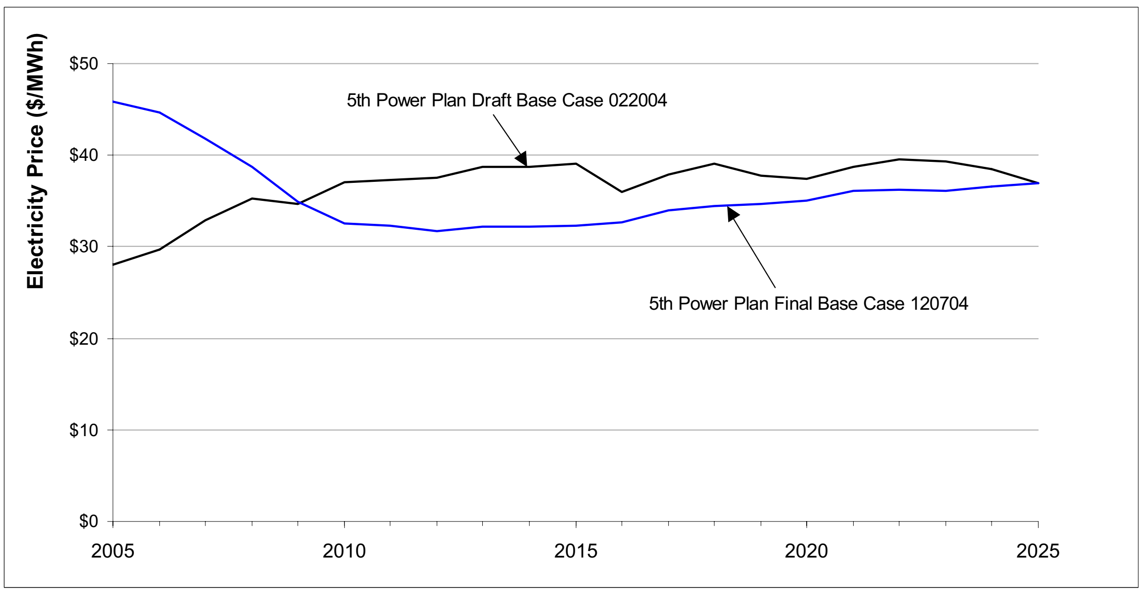


Figure C-1: Draft and final base case forecasts of average annual wholesale electricity prices at the Mid-Columbia trading hub

The final forecast prices decline from 2003 highs as gas prices decline, leveling off about 2012 as growing loads exhaust the current generating capacity and new capacity development ensues. Prices slowly increase through the remainder of the planning period under the influence of slowly increasing natural gas prices, new resource additions, declining renewable energy incentives and increasing CO_2 penalties. Not included in the forecast are likely episodic price excursions resulting from gas price volatility or poor hydro conditions.

The annual average prices of Figure C-1 conceal important seasonal price variation. Seasonal variation is shown in the plot of monthly average Mid-Columbia prices in Figure C-2. Also plotted in Figure C-2 are monthly average Northwest loads and monthly average Southern California loads. The winter-peaking character of Northwest loads (driven by lighting and heating loads) and the more pronounced summer-peaking character of the Southern California loads (driven by air conditioning and irrigation loads) are evident. A strong winter Mid-Columbia price peak, driven by winter peaking Northwest loads is present throughout the forecast. A secondary summer price peak is also present because spot market prices in the Northwest will follow Southwest prices as long as capacity to transmit electricity south is available on the interties. The summer Mid-Columbia price peak begins to increase in magnitude midway through the planning period as California loads grow relative to Northwest loads. The summer price peak increases the value of summer-peaking efficiency resources such as irrigation efficiency improvements.

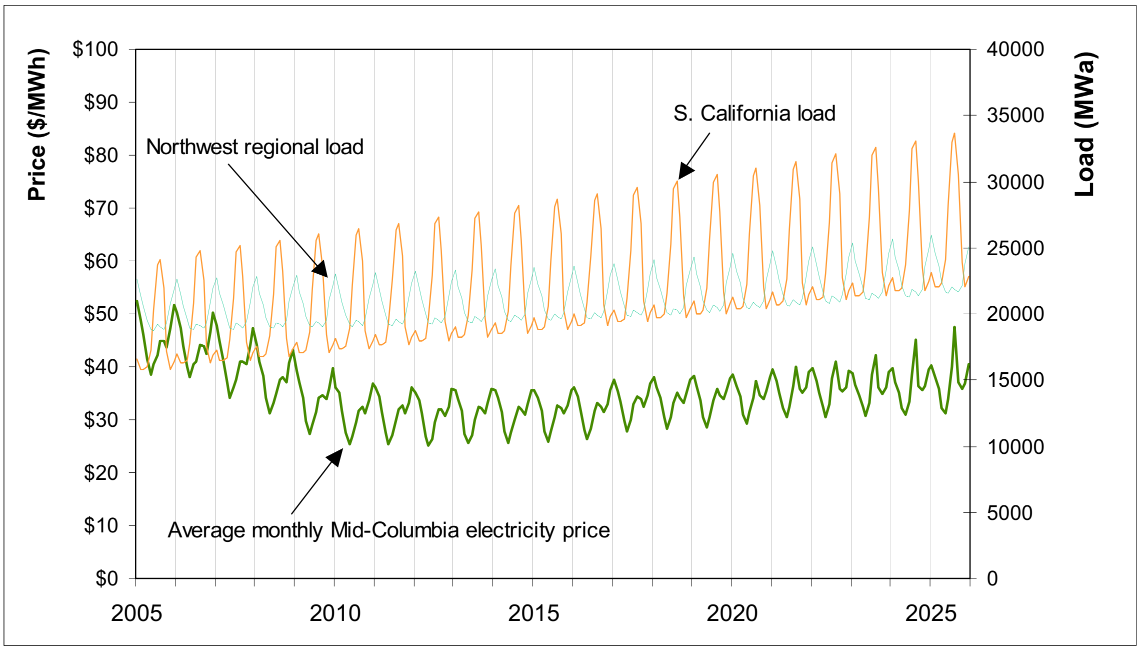


Figure C-2: Monthly wholesale Mid-Columbia prices compared to Northwest and Southwest load shapes

Daily variation in prices is significant as well, with implications for the cost-effectiveness of certain conservation measures. Typical daily price variation is shown in Figure C-3 - a snapshot of the hourly Mid Columbia forecast for a summer week.

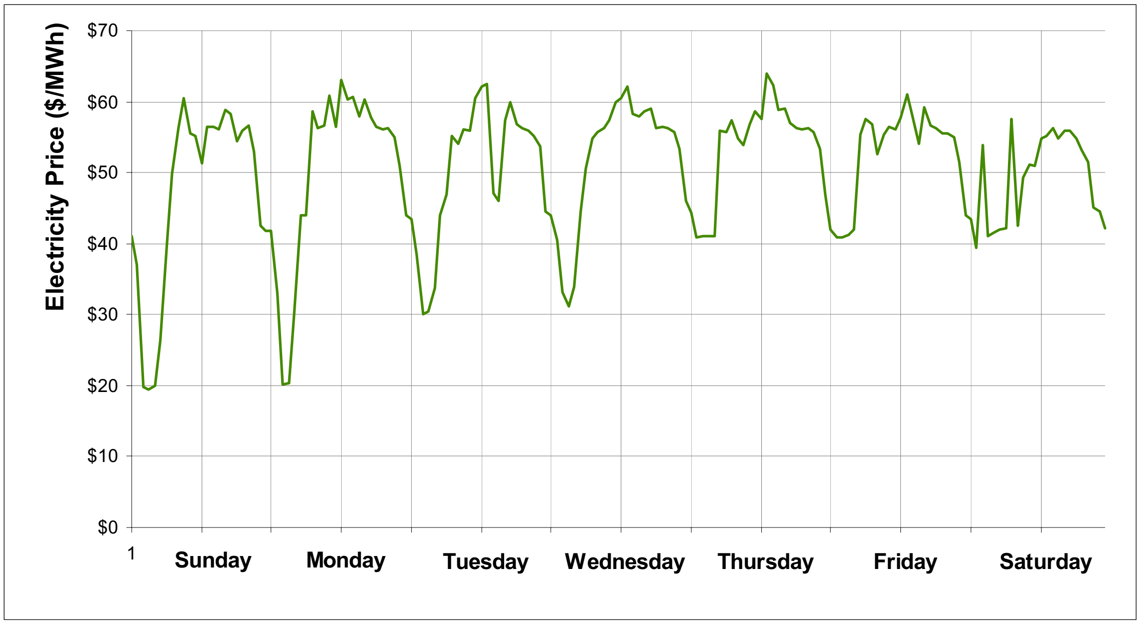


Figure C-3: Illustrative hourly prices (July 31- August 7, 2005)

The forecast annual average prices for the Mid-Columbia trading hub and for other Northwest load-resource zones is provided in Table C-1. Monthly and hourly price series are available from the Council on request.

Table C-1: Forecast annual average wholesale electricity prices for Northwest load-resource zones

Year	West of Cascades	Mid-Columbia (Eastside)	S. Idaho	E. Montana
2005	45.99	45.84	45.16	44.86
2006	44.84	44.68	44.02	43.67
2007	41.99	41.76	41.06	40.79
2008	38.93	38.71	37.82	37.72
2009	35.11	34.94	33.87	33.84
2010	32.65	32.52	31.50	31.39
2011	32.42	32.31	31.41	31.20
2012	31.85	31.75	30.91	30.64
2013	32.27	32.17	31.35	31.06
2014	32.25	32.15	31.35	31.04
2015	32.37	32.28	31.49	31.18
2016	32.76	32.66	31.90	31.54
2017	34.07	33.99	33.24	32.86
2018	34.54	34.46	33.78	33.34
2019	34.74	34.67	34.08	33.60
2020	35.12	35.05	34.55	33.97
2021	36.16	36.08	35.80	35.04
2022	36.25	36.18	36.11	35.15
2023	36.10	36.05	36.12	35.00
2024	36.58	36.52	36.70	35.53
2025	37.06	36.99	37.40	36.01

The base case forecast resource mix for the interconnected Western Electricity Coordinating Council (WECC) area is shown in Figure C-4. Factors affecting resource development through the 2005-2025 period include load growth, natural gas prices, generating resource technology improvement, continued renewable resource incentives and increasing probability of carbon dioxide production penalties. Principal additions between 2005 and 2025 include approximately 4,600 megawatts of renewable resources resulting from state renewable portfolio standards and system benefit charges, 17,000 megawatts of combined-cycle plant, 20,000 megawatts of steam coal capacity, 22,000 megawatts of wind capacity and 9,000 megawatts of coal gasification combined-cycle plant. Retirements include 1,650 MW of steam coal, 1,400 MW of gas combined-cycle and 1,400 MW of gas steam units. The 2025 capacity mix includes 33 percent natural gas, 25 percent hydropower, 24 percent coal and 11 percent intermittent renewables (wind and solar). Not shown in the figure is about 9,000 megawatts of demand response capability assumed to be secured between 2007 and 2025.

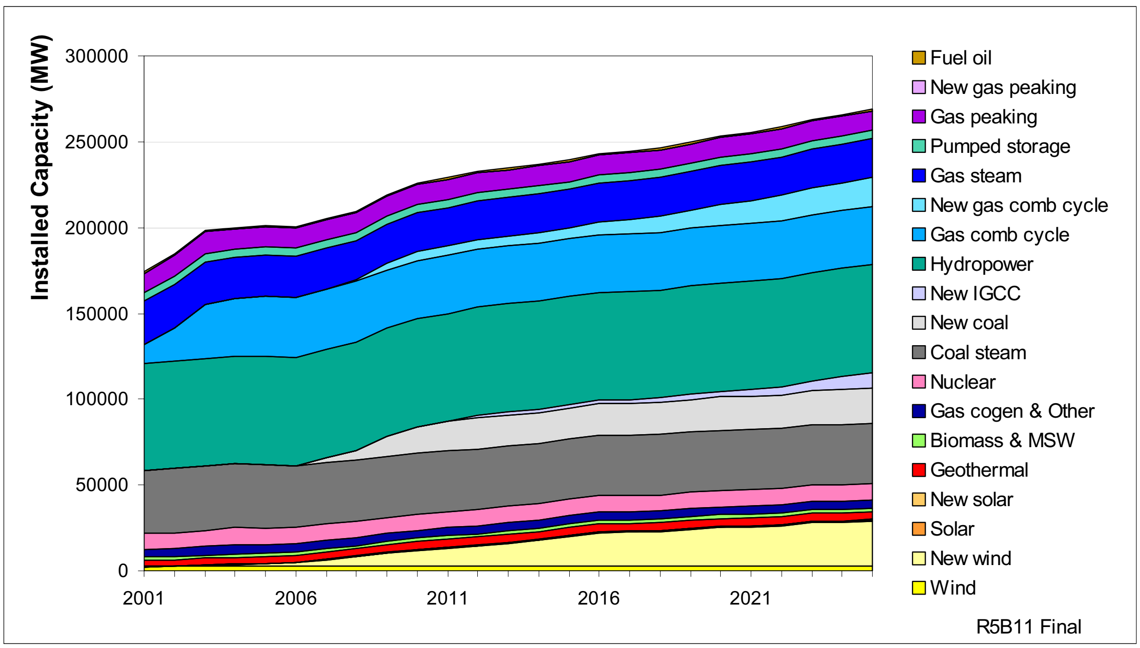


Figure C-4: Base case WECC resource mix

The Northwest resource mix is shown in Figure C-5. About 960 megawatts of renewables funded by state system benefit charges (modeled as wind) and 2,900 additional megawatts of new, market-driven wind power are added during the period 2005-25 in addition to the 399 MW Port Westward combined-cycle plant, currently under construction. No capacity is retired. The regional capacity mix in 2025 includes 67 percent hydropower, 13 percent natural gas, 9 percent wind and 8 percent coal. Not shown in the figure is about 1,900 megawatts of demand response capability assumed to be secured between 2007 and 2025. Because the capacity addition logic used for this forecast uses deterministic fuel prices, loads, renewable production credits, CO_2 penalties and other values affecting resource cost-effectiveness, the resulting resource additions differ somewhat from the recommendations resulting from the more sophisticated risk analysis described in Chapter 7 of the plan.

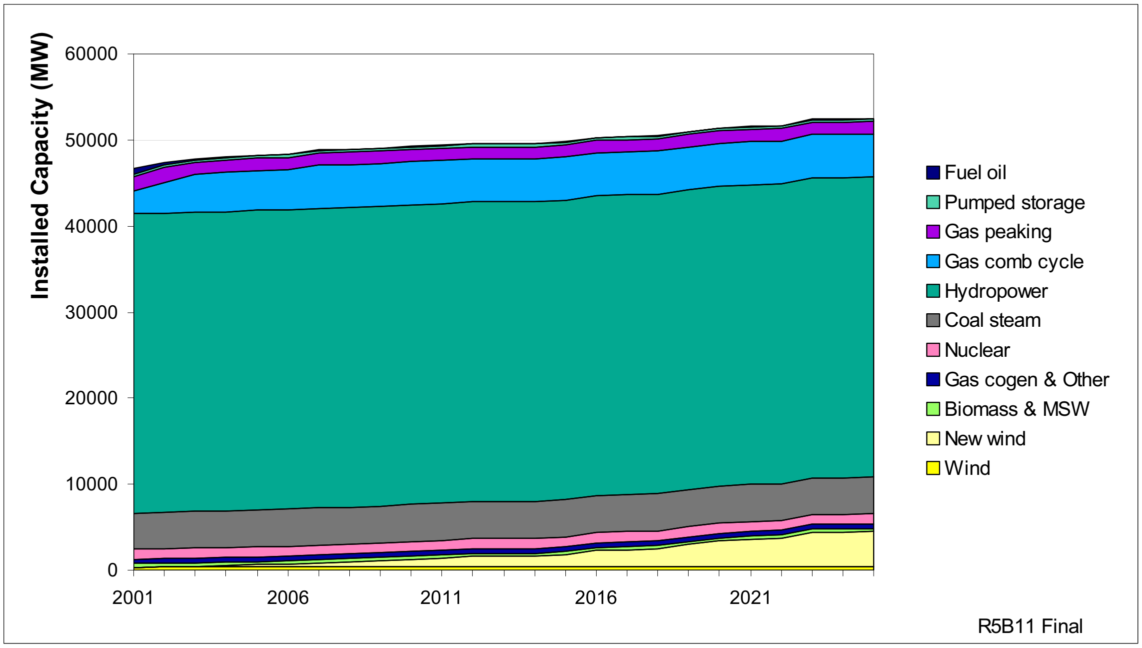


Figure C-5: Base case Pacific Northwest resource mix

Other base case results are summarized in Table C-3. Further detail can be found in the workbook PLOT R5B11 Final Base 012705.xls, posted in the Council's website dropbox.

APPROACH

The Council forecasts wholesale electricity prices using the AURORA$^{xmp®}$ electricity market model. Electricity prices are based on the variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period. A forecast is developed using the two-step process illustrated in Figure C-6. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using the AURORA$^{xmp®}$ long-term resource optimization logic. This is an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, operation, maintenance and fuel, including a return on the developer's investment and a dispatch premium. This step results in a future resource mix such as depicted for the base case in Figure C-4.

The electricity price forecast is developed in the second step, in which the mix of resources developed in the first step is dispatched on an hourly basis to serve forecast loads. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the forecast price.

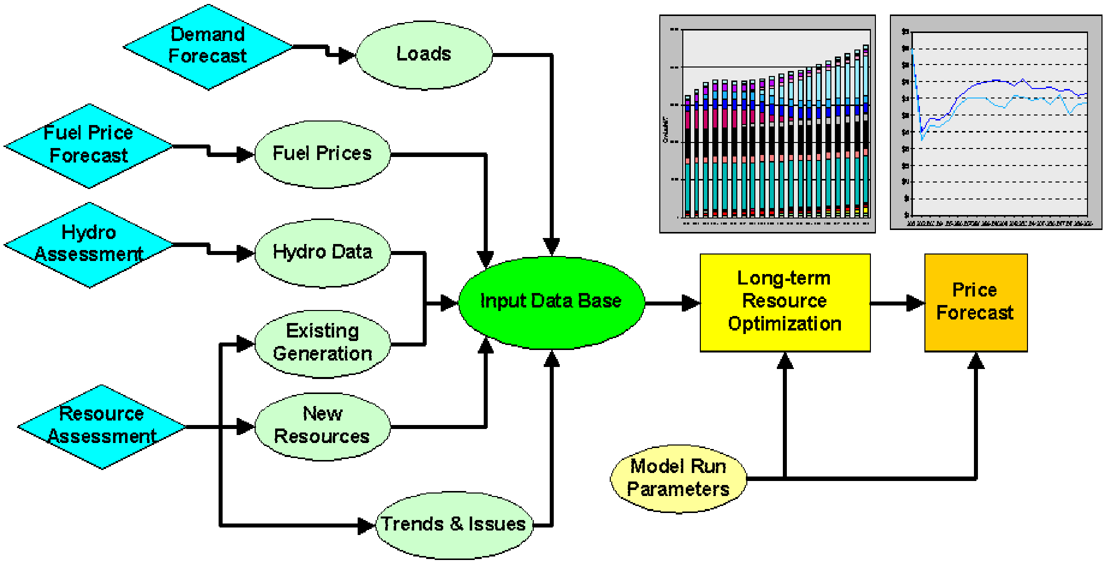


Figure C-6: Price forecasting process

As configured by the Council, AURORA$^{xmp®}$ simulates power plant dispatch in each of 16 load-resource zones that make up the WECC electric reliability area (Figure C-7). These zones are defined by transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource zone may be served by native generation, curtailment, or by imports from other load-resource zones if economic, and if transmission transfer capability is available.

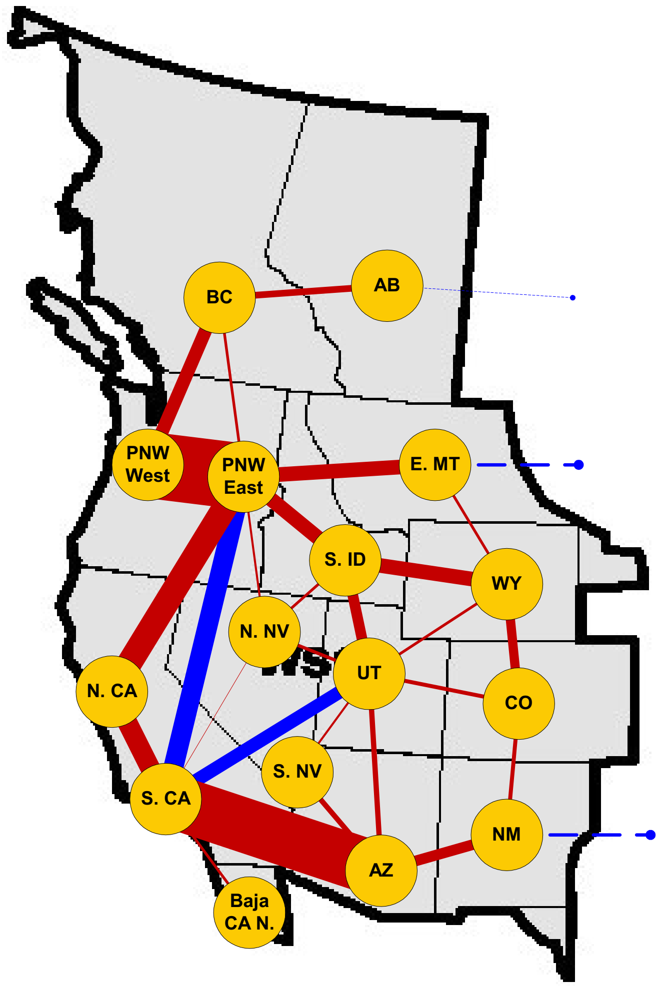


Figure C-7: Load-resource zones

DATA, ASSUMPTIONS AND SENSITIVITY ANALYSES

The data and assumptions underlying the electricity price forecast are developed by the Council with the assistance of its advisory committees (Appendix C-1). The base forecast is an expected value forecast using the medium case electricity sales forecast, the medium case forecast of fuel prices and average water conditions. Though possible future episodes of fuel price and hydropower volatility are not specifically modeled, water conditions and fuel prices are adjusted to compensate for the biasing effect of volatility on electricity prices. The base case forecast uses the mean annual values of federal renewable production tax credits, renewable energy credit revenues and possible future carbon dioxide penalties from the portfolio risk analysis.

Electricity Loads

The Council's medium case electricity sales forecast is the basis for the base case electricity price forecast for Northwest load-resource zones. Transmission and distribution losses are added and the effects of price-induced and programmatic conservation deducted to produce a load forecast. In the medium-case forecast, Northwest loads, including eastern Montana are forecast to grow at an average annual rate of approximately 0.7 percent per year from 20,875 average megawatts in 2005 to 23,850 average megawatts in 2025. Direct Service Industry loads average 200 megawatts in the medium case.

Total WECC load is forecast to grow at an annual average rate of 1.7 percent, from about 94,800 average megawatts in 2005 to 132,100 average megawatts in 2025. Most load-resource zones outside the Northwest are forecast to see more rapid load growth than Northwest areas (Table C-2). The approach used to forecast loads for load-resource zones outside the Northwest was to calculate future growth in electricity demand as the historical growth rate of electricity use per capita times a forecast of population growth rate for the area. Exceptions to this method were California, where forecasts by the California Energy Commission were used, and the Canadian provinces, where load forecasts are available from the National Energy Board.

Table C-2: Base loads and medium case forecast load growth rates[a]

Load-resource zone	2005 (Average Megawatts)	2025 (Average Megawatts)	Average Annual Load Growth, 2005-2025
PNW Eastside (WA & OR E. of Cascade crest, Northern ID & MT west of Continental Divide.	4695	5341	0.6 percent
PNW Westside (WA & OR W. of Cascade crest)	12832	14661	0.7 percent
Southern Idaho (~IPC territory)	2518	3022	0.9 percent
Montana E. (east of Continental Divide)	830	829	0.0 percent
Alberta	6023	8489	1.6 percent
Arizona	8513	13867	1.4 percent
Baja California Norte	1117	1883	2.6 percent
British Columbia	7798	10199	1.4 percent
California N. (N. of Path 15)	13842	18794	1.5 percent
California S. (S. of Path 15)	18431	25686	1.7 percent
Colorado	6011	9498	2.3 percent
Nevada N. (~ SPP territory)	1294	1941	2.0 percent
Nevada S. (~ NPC territory)	2586	4466	2.8 percent
New Mexico	3099	5670	3.1 percent
Utah	3256	5702	2.7 percent
Wyoming	1814	2046	0.6 percent
Total	**94847**	**132094**	**1.7 percent**

a) Load is forecast sales plus 8 percent transmission and distribution loss.

Sensitivity studies were run using the Council's medium-low and medium-high case electricity sales forecast to assess the implications of long-term load growth uncertainty on electricity prices and resource development. Growth rates for load-resource zones outside the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the percentile growth rate differences between the Northwest medium case (0.7%/yr) and medium-low case (0.1%/yr) and medium-high case (1.3%/yr), respectively.

As expected, the faster load growth of the medium-high load growth case result in higher electricity prices throughout the forecast period (Figure C-8). Beginning about 2017, the medium-high case prices climb rapidly away from the base case prices. This appears to result from accelerated development of natural gas combined-cycle plants at this time. It is likely that gas is selected over coal because of increasing CO_2 mitigation cost. Levelized Mid-Columbia prices are $37.70 per megawatt-hour, 4 percent higher than the base case.

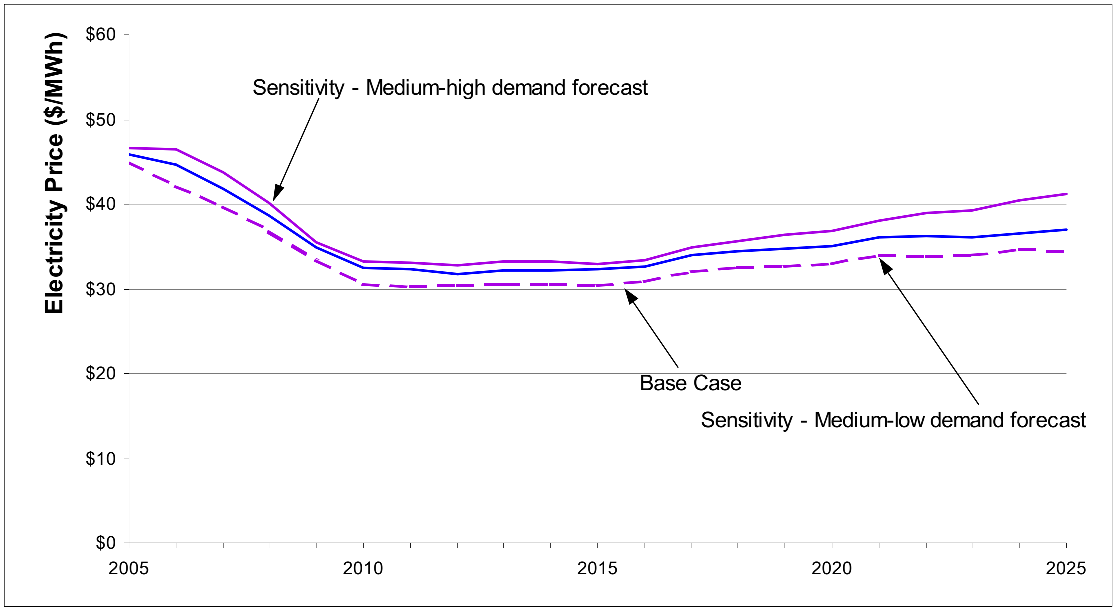


Figure C-8: Sensitivity of Mid-Columbia electricity price to load growth uncertainty

The medium-low case results in consistently lower Mid-Columbia prices (Figure C-8). Levelized Mid-Columbia prices are $34.30 per megawatt-hour, 5 percent lower than the base case.

Other results of the load sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final MLDmd 033005.xls, PLOT R5B11 Final MHDmd 041005.xls, posted in the Council's website dropbox.

Fuel Prices

The Council's medium case fuel price forecast is used for the base case electricity price forecast. Coal prices are based on forecast Western mine-mouth coal prices, and natural gas prices are based on a forecast of U.S. natural gas wellhead prices. Basis differentials are added to the base prices to arrive at delivered fuel prices for each load-resource zone. Natural gas prices are further adjusted for seasonal variation. For example, the price of natural gas delivered to a power plant located in western Washington or Oregon is based on the annual average U.S. wellhead price forecast, adjusted by price differentials between wellhead and Henry Hub (Louisiana); Henry Hub and AECO hub (Alberta); AECO and (compressor) Station 2, British Columbia; and finally, Station 2 and western Washington and Oregon. A monthly adjustment is applied to the AECO - Station 2 differential. The fuel price forecasts and derivation of load-resource area prices are more fully described Appendix B.

In the medium case, the price of Western mine-mouth coal is forecast to hold at $0.51 per million Btu from 2005 through 2025 (constant 2000$). Average distillate fuel oil prices are forecast to stabilize at $6.58 by 2010, following a decline from $7.15 per million Btu in 2005. Price-driven North American exploration and development, increasing liquefied natural gas imports and demand destruction are expected to slowly force down average annual U.S. wellhead natural gas prices from $5.30 per million Btu in 2005 to a low of $3.80/MMBtu in 2015. The annual average price is then forecast to then rise slowly to $4.00 per million Btu in 2025 (2000$), capped by the expected cost of landed liquefied natural gas.

Forecast medium-case delivered prices for selected fuels are plotted in Figure C-9. Fuel prices are shown in Figure C-9 as fully variable (dollars per million Btu) to facilitate comparison. However, the price of delivered coal and natural gas is modeled as a fixed (dollars per kilowatt per year) and a variable (dollars per million Btu) component to differentiate costs, such as pipeline reservation costs that are fixed in the short-term.

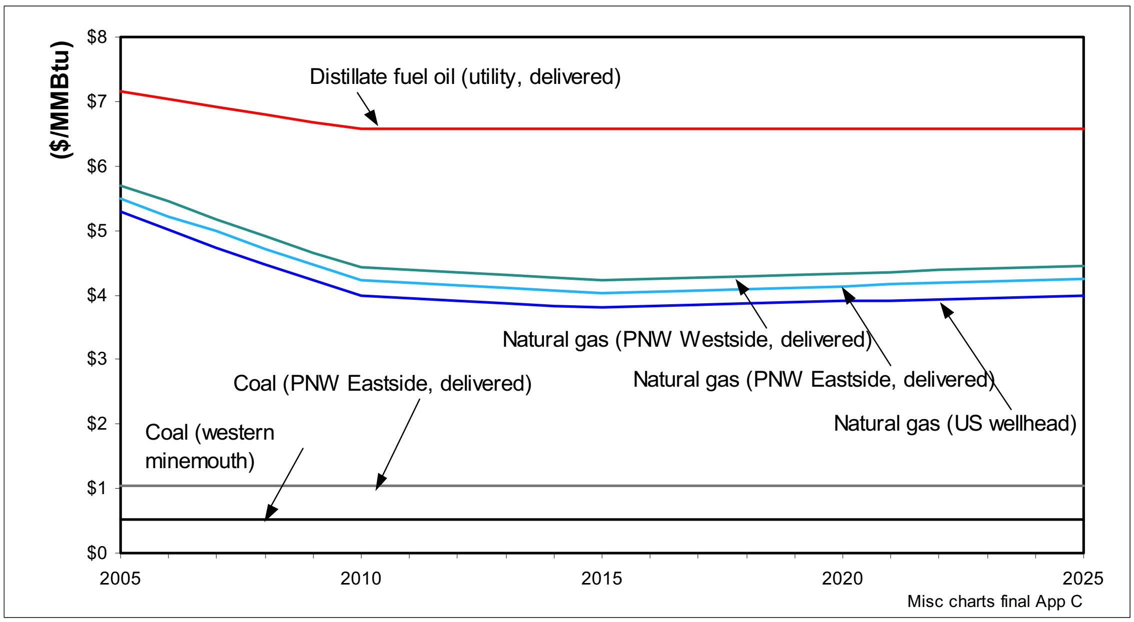


Figure C-9: Forecast prices for selected fuels - Medium Case

Sensitivity analyses were run using the Council's high case and low case fuel price forecasts to examine the effects of higher or lower fuel prices on the future resource mix and electricity prices. The high case and the low case fuel price forecasts for wellhead gas and minemouth coal are compared to the medium case forecasts in Figure C-10.

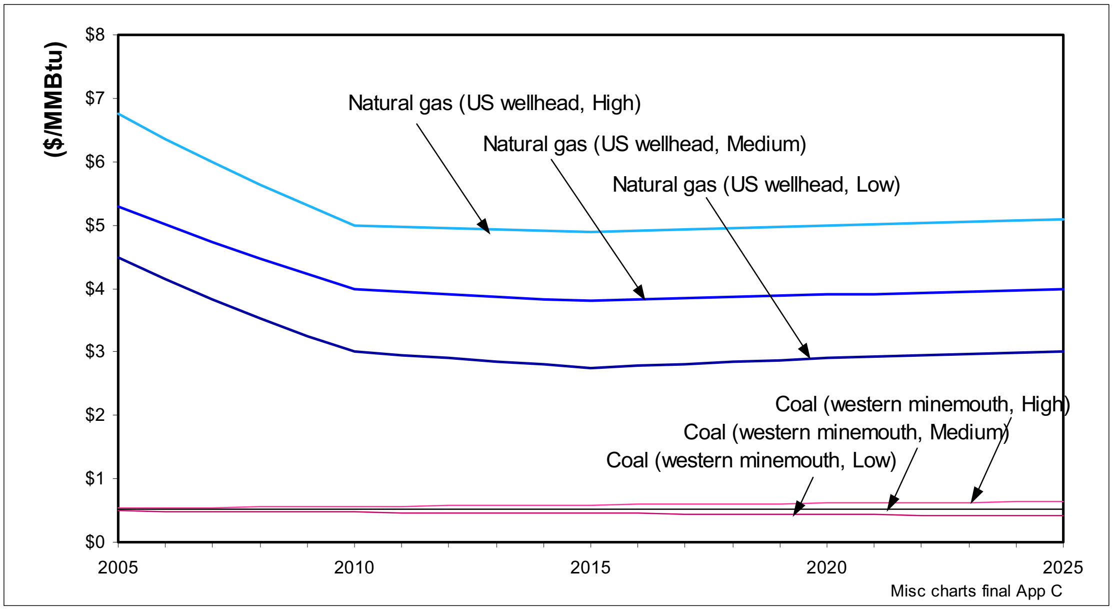


Figure C-10: Natural gas and coal price forecast cases

The low fuel price forecast results in levelized Mid-Columbia electricity prices of $29.80 per megawatt-hour, 18 percent lower than the base case. The lower price is evident throughout the forecast period, possibly as a manifestation of continued reliance on gas-fired combined-cycle power plants (Figure C-11). The 2025 resource mix (Table C-3) shows a shift away from new coal and wind to new gas-fired units. Also evident in Table C-3 is the substantial reduction in CO_2 production associated with the greater penetration of natural gas. If this were intended to be a scenario rather than a sensitivity case, the higher loads resulting from lower prices would offset a portion of the potential CO_2 reduction.

The high fuel price forecast results in levelized Mid-Columbia electricity prices of $39.60 per megawatt-hour, 9 percent higher than the base case. Prices are substantially higher in the near-term, but moderate toward base case values by 2015 as new coal-fired power plants supplement existing gas-fired capacity (Figure C-11). The 2025 resource mix (Table C-3) shows a strong shift to new conventional coal and IGCC plants and wind in lieu of new gas-fired capacity. Towards the end of the forecast period, increasing CO_2 mitigation costs result in electricity prices again rising above base case values.

Other results of the fuel price sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final LoFuel 031705.xls, PLOT R5B11 Final HiFuel 031605.xls, posted in the Council's website dropbox.

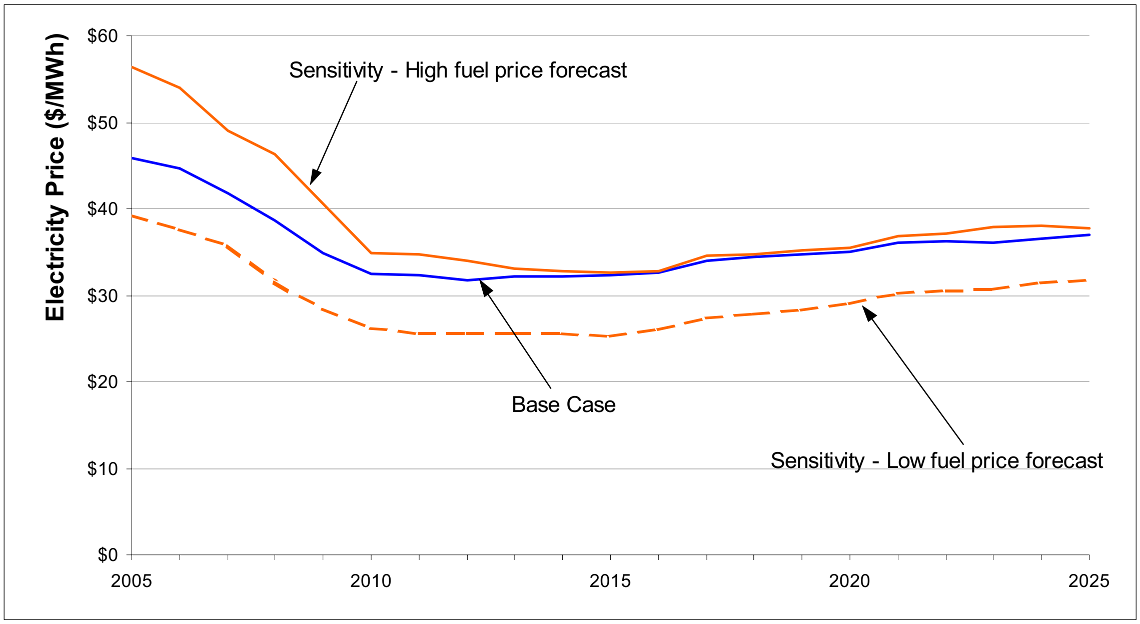


Figure C-11: Sensitivity of Mid-Columbia electricity price to fuel price uncertainty

Demand Response

Demand response is a change in the level or quality of service that is voluntarily accepted by the consumer, usually in exchange for payment. Demand response can shift load from peak to off-peak periods and reduce the cost of generation by shifting the marginal dispatch to more efficient or otherwise less-costly units. Demand response may also be used to reduce the absolute amount of energy consumed to the extent that end-users are willing to forego net electricity consumption in return for compensation. The attractiveness of demand response is not only its ability to reduce the overall cost of supplying electricity; it also rewards end users for reducing consumption during times of high prices and possible supply shortage. Demand response also offers many of the environmental benefits of conservation.

Though the understanding of demand response potential remains sketchy, preliminary analysis by the Council suggests that ultimately up to 16 percent of load might be offset at a cost of $50 to $400 per megawatt-hour through various forms of time-of-day pricing and negotiated agreements. For the base case forecast, we assume that 50 percent of this potential is secured, beginning in 2007 and ramping up to 2025. Similar penetration is assumed throughout WECC.

Existing Generating Resources

The existing power supply system modeled for the electricity price forecast consisted of the projects within the WECC interconnected system in service and under construction as of the first quarter of 2003. Three Northwest gas combined-cycle power plants for which construction was suspended, Grays Harbor, Mint Farm and Montana First Megawatts were included as new generating resource options. Projects having announced retirement dates were retired as scheduled.

New Generating Resource Options

When running a capacity expansion study, AURORA$^{xmp®}$ adds capacity when the net present value cost of adding a new unit is less than the net present market value of the unit. Because of study run time considerations, the number of available new resource alternatives is limited to those possibly having a significant effect on future electricity prices. Some resource alternatives such as gas combined-cycle plants and wind are currently significant and likely to remain so. Others, such as new hydropower or various biomass resources, are unlikely to be available in sufficient quantity to significantly influence future electricity prices. Some, such as coal gasification combined-cycle plants or solar photovoltaics do not currently affect power prices, but may do so as the technology develops and costs decline. Resources such as new generation nuclear plants or wave energy plants were omitted because they are unlikely to be commercially mature during the forecast period. Others, such as gas-fired reciprocating generator sets were omitted because they are not markedly different from simple-cycle gas turbines with respect to their effect on future electricity prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, wind power, coal-fired steam-electric power plants, coal gasification combined-cycle plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

Natural gas-fired combined cycle power plants

The high thermal efficiency, low environmental impact, short construction time and excellent operating flexibility of natural gas-fired combined-cycle plants helped make this technology becoming the "resource of choice" in the 1990s. In recent years, high natural gas prices have dimmed the attractiveness of combined-cycle plants and many projects currently operate at low load factors. Though technology improvements are anticipated to help offset high natural gas prices, the future role of this resource is sensitive to natural gas prices and global climate change policy. Higher gas prices could shift development to coal or windpower. More stringent carbon dioxide offset requirements might favor combined-cycle plants because of their proportionately lower carbon dioxide production. The representative natural gas combined-cycle power plant used for this forecast is a 2x1 (two gas turbines and one steam turbine) plant of 540 megawatts of baseload capacity plus 70 megawatts of power augmentation (duct-firing) capacity.

Wind power plants

Improved reliability, cost reduction, financial incentives and emerging interest in the hedge value of wind with respect to gas prices and greenhouse gas control policy have moved wind power from niche to mainstream over the past decade. The cost of wind-generated electricity (sans financial incentives) is currently higher than electricity from gas combined-cycle or coal plants, but it is expected to decline to competitive levels within several years. The future role of wind is dependent upon gas price, greenhouse gas policy, continued technological improvement, the cost and availability of transmission and shaping services and the availability of financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is an expectation that coal may be subject to future CO_2 penalties. At current costs, it is infeasible to extend transmission more than several miles to integrate a wind project with the grid. This limits the availability of wind to prime resource areas close to the grid. As wind plant costs decline, feasible interconnection distances will extend, expanding wind power potential. Two cost blocks of wind in 100 MW plant increments were defined for this study - a lower cost block representing good wind resources and low shaping costs, and a higher cost block representing the next phase of wind development with somewhat less favorable wind (lower capacity factor) and higher shaping costs.

Coal-fired steam-electric power plants

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, relatively low fuel prices, improvements in technology and concerns regarding future natural gas prices have repositioned coal as a potentially economically attractive new generating resource. Conventional steam-electric technology would likely be the coal technology of choice in the near-term. Supercritical steam technology is expected to gradually penetrate the market and additional control of mercury emissions is likely to be required. The representative new coal-fired power plant defined for this forecast is a 400-megawatt steam-electric unit. Costs and performance characteristics simulate a gradual transition to supercritical steam technology over the planning period.

Coal-gasification combined-cycle power plants

Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation. This improves fuel use efficiency, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers. A 425-megawatt coal-gasification combined-cycle power plant without CO2 separation and sequestration was modeled for the price forecast.

Natural gas-fired simple-cycle gas turbine generators

Gas turbine generators (simple-cycle gas turbines), reciprocating engine-generator sets, supplementary (duct) firing of combined-cycle plants are potentially cost-effective means of supplying peaking and reserve power needs. As described earlier, the Council also views demand response as a promising approach to meeting peaking and reserve power needs. Supplementary ("duct") firing of gas combined-cycle plants can also help meet peaking or reserve needs at low cost and is included in the generic combined-cycle plant described above. Additional requirements can be met by simple-cycle gas turbine or reciprocating generator sets. From a modeling perspective, the cost and performance of gas-fired simple-cycle gas turbines and gas-fired reciprocating engine-generator sets are sufficiently similar that only one need be modeled. The Council chose to model a twin-unit (2 x 47 megawatt) aeroderivative simple-cycle gas turbine generator set.

Central-station solar photovoltaics

Solar power is one of the most potentially attractive and abundant long-term power supply alternatives. Economical small-scale applications of solar photovoltaics are currently found throughout the region where it is costly to secure grid service, however for bulk, grid-connected supply, solar photovoltaics are currently much more expensive than other bulk supply alternatives. Because of the potential for significant cost reduction, the Council included a 100 MW central-station solar photovoltaic plant as a long-term bulk power generating resource alternative.

The cost and performance characteristics of these generating resource alternatives are further described in Chapter 5 and Appendix I.

Transmission

Transfer ratings between load-resource zones are based on the 2003 WECC path ratings plus scheduled upgrades to Path 15 between northern and southern California (since completed) and scheduled upgrades between the Baja California and southern California.

Renewable Energy Production Incentive

Federal, state and local governments for many years have provided incentives to promote various forms of energy production, including research and development grants and favorable tax treatment. A federal incentive that significantly affects the economics of renewable resource development is the renewable energy production tax credit (PTC) and the companion renewable energy production incentive (REPI) for tax-exempt entities. Enacted as part of the 1992 Energy Policy Act, and originally intended to help commercialize wind and certain biomass technologies, these incentives have been repeatedly renewed and extended, and currently amount to approximately $13 per megawatt hour (2004 dollars) when levelized over the life of a project. The incentive expired at the end of 2003 but, in September 2004, was extended to the end of 2005, retroactive to the beginning of 2004. In addition, the scope of qualifying facilities was extended to forms of biomass, geothermal, solar and certain other renewable resources not previously qualifying. The long-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as above-market resource costs are reduced. In addition, federal budget constraints may eventually force reduction or termination of the incentives. However, the incentives remain politically popular, as they encourage development that produces rural property tax revenues and revenue for local landowners on whose land wind turbines are sited. Moreover, the incentives serve as a crude carbon dioxide control mechanism in the absence of a federal climate change policy.

Because of these uncertainties, future federal renewable energy production incentive were modeled as a stochastic variable in the portfolio risk analysis, as described in Chapter 6. The mean annual value from the portfolio risk analysis was used for the base case electricity price forecast and for all sensitivity cases (Figure C-12). Because of practical considerations, state and local financial incentives, such as sales and property tax exemptions, were not modeled.

Renewable Energy Credits

Electricity from renewable energy projects often commands a market premium. Typically, the premium is traded separately from the electricity, in the form of renewable energy credits (RECs, or "green tags"). The REC market is driven by the demand for green power products, the nascent demand for CO_2 offsets and by the demand for resources to meet state renewable portfolio standard obligations. The current market value of green tags for electricity from newer windpower projects is reported to be $3 to $4 per megawatt-hour. Tag prices for solar-generated electricity generally higher than wind tags, and tag prices for hydro, biomass and geothermal power are generally lower. Electricity from newer renewable energy projects typically commands higher tag prices than that from older projects. Future REC revenues were modeled as a stochastic variable in the portfolio risk analysis as described in Chapter 6. The mean annual REC value from the portfolio risk analysis (Figure C-12) was used for both wind and solar power in the base and sensitivity cases.

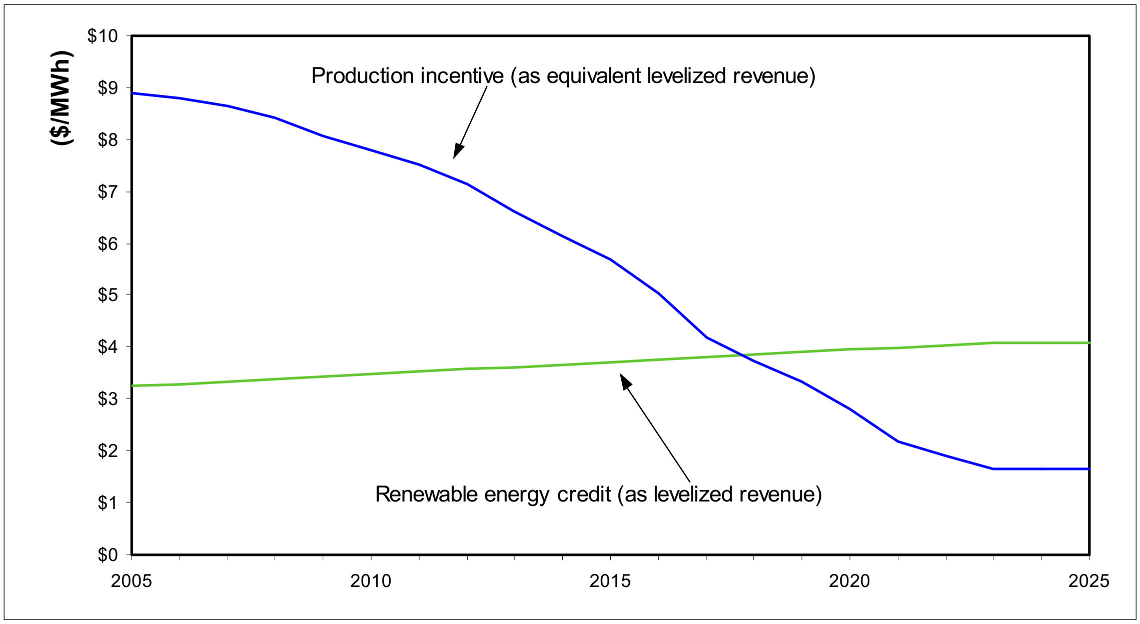


Figure C-12: Renewable energy incentives

Global Climate Change Policy

In the absence of federal initiatives, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Since 1997, Oregon has required mitigation of 17 percent of the carbon dioxide production of new power plants. Washington, in 2004 adopted CO_2 mitigation requirements for new fossil power plants exceeding 25 megawatts capacity. In Montana, the developer of the natural gas-fired Basin Creek Power Plant has agreed to mitigate CO_2 production to the Oregon requirements. California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Though it appears likely that CO_2 production from power generation facilities will be subject to increasing regulation over the period of this plan, the nature and timing of future controls is highly uncertain. For this reason, CO_2 mitigation costs were modeled in the portfolio risk analysis as a stochastic carbon tax. The probabilities and distributions used to derive the carbon tax for the portfolio analysis are described in Chapter 6. In the base case electricity price forecast, the mean annual value of the carbon tax from the portfolio risk analysis is applied to both existing and new generating resources. Unlike the portfolio analysis, the current Oregon mitigation requirements are applied to new resources developed in Washington or Oregon until this value is exceeded by the mean annual values from the portfolio analysis (Figure C-13).

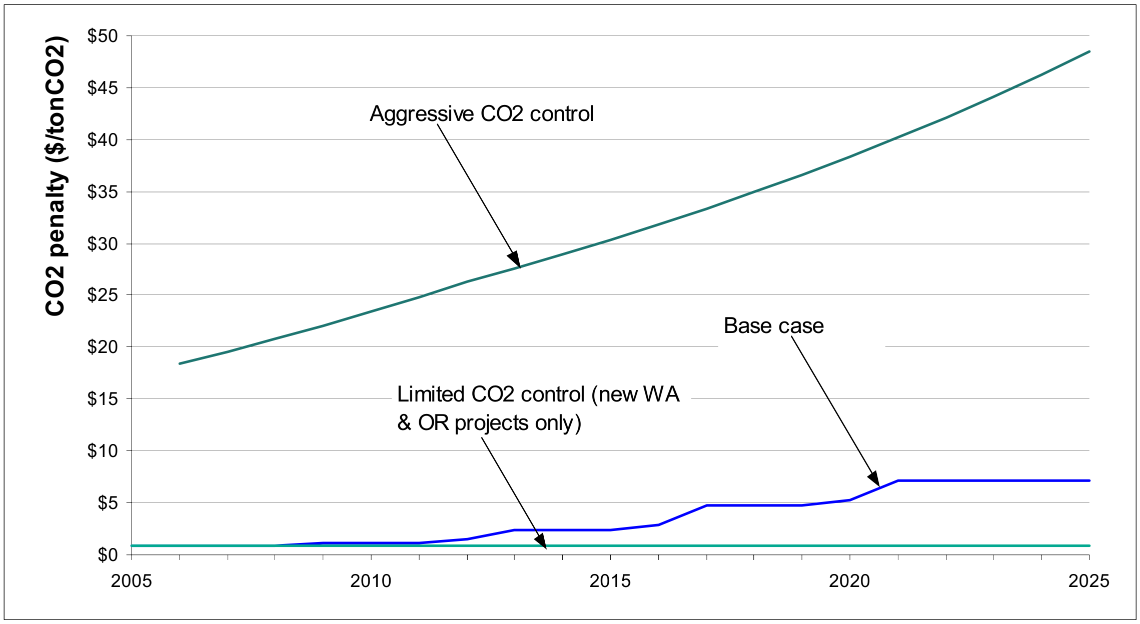


Figure C-13: CO_2 mitigation cost (as carbon tax)

Because of uncertainties regarding future CO_2 regulation, two sensitivity analyses were run. A limited CO_2 control case assumed that CO_2 mitigation continues to be required only in Oregon and Washington at a cost of $0.87 per ton CO_2 (approximately the current Oregon fixed payment option). Compared to the base case, this shifts future resource development from wind and natural gas combined-cycle plants to conventional and gasified coal (Table C-3). Additional older gas steam capacity is retired. The levelized Mid-Columbia price declines by 6 percent to $33.90 per megawatt-hour (Figure C-14). The most significant price reduction is experienced in the longer-term as the resource mix shifts from more expensive natural gas capacity to less expensive coal (Figure C-14). The additional new fossil capacity leads to a larger 2025 WECC system average CO_2 production factor of 0.576 lbCO_2/kWh, 14 percent greater than that of the base case value of 0.507 lb CO_2/kWh (Figure C-15). Cumulative WECC CO_2 production for the period 2005-25 increases by 7 percent.

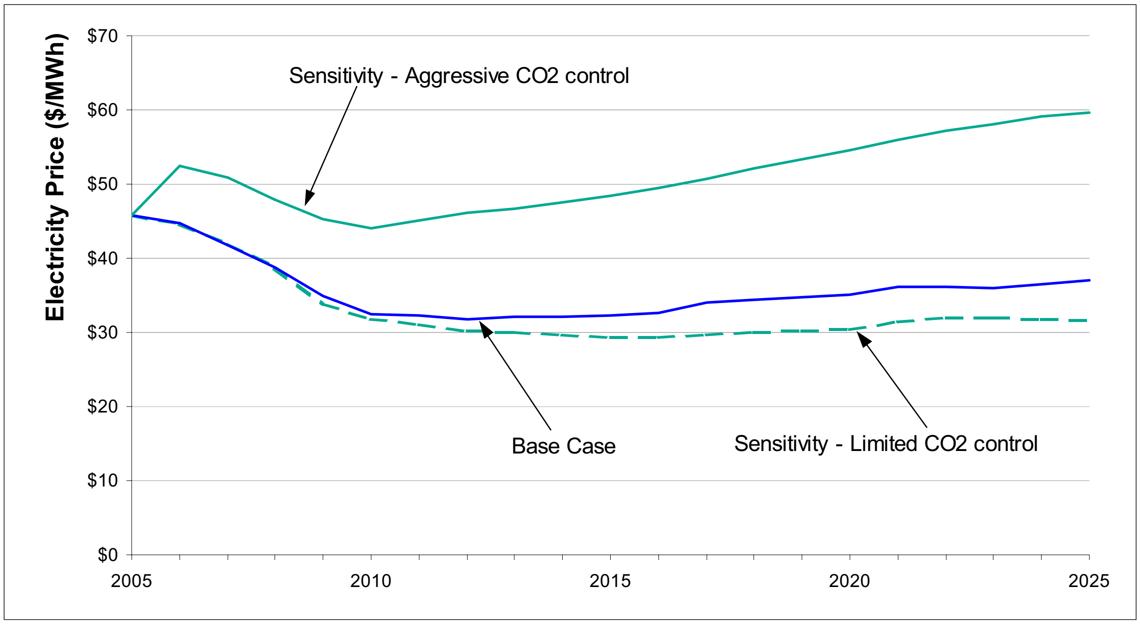


Figure C-14: Sensitivity of electricity price forecast to CO_2 mitigation cost

An aggressive CO_2 control effort was modeled by approximating the nationwide cap and trade program proposed in the McCain-Lieberman Climate Stewardship Act. McCain-Lieberman would implement capped and tradable emissions allowances for CO_2 and other greenhouse gasses. Reduction requirements would apply to large commercial, industrial and electric power sources. The proposal rejected by the Senate in a 43-55 vote in 2003 would have capped allowances at 2000 levels by 2010 and 1990 levels in 2016.

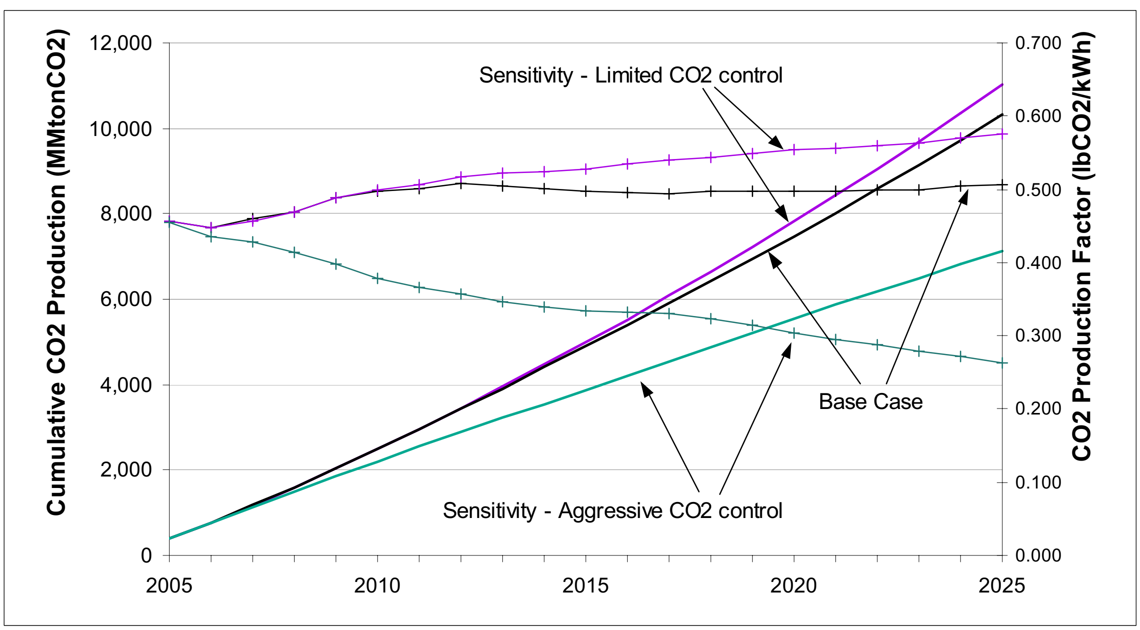


Figure C-15: Sensitivity of forecast WECC CO_2 production to CO_2 mitigation cost

The aggressive CO_2 control sensitivity case is based on the assumed enactment of federal regulation similar to the McCain-Lieberman proposal in 2006, with the year 2000 cap in effect in 2012. Model limitations require CO_2 mitigation cost to be treated as a carbon tax on fuel use rather than as a true cap and trade system. In this case, fuel carbon for existing and new projects is taxed at the equivalent of a forecast cost of CO_2 allowances required to achieve the proposed McCain-Lieberman cap[1]. The allowance costs needed to achieve the targeted reductions of the McCain-Lieberman proposal are highly uncertain but were the subject of a Massachusetts Institute of Technology (MIT) analysis[2]. The sensitivity study was based on the forecast CO_2 allowance costs of Case 5 of the MIT study, shifted back two years to coincide with the assumed 2012 Phase I implementation date. A market in banked allowances was assumed to develop on enactment in 2006 so any subsequent reduction in fuel carbon consumption is valued at an opportunity cost equivalent to the discounted forecast 2012 allowance cost. Oregon and Washington were assumed to continue their current mitigation standards at \$0.87 per ton through 2006.

These assumptions result in a significant shift in the future resource mix compared to the base case. Wind and gas combined-cycle resource development is accelerated and additions of bulk solar photovoltaics appear near the end of the forecast. About 6 percent of existing coal capacity and 17 percent of existing gas steam capacity is retired over the forecast period. New coal development is entirely absent (Table C-3). The levelized forecast Mid-Columbia price is \$50.10 per megawatt-hour, 38 percent higher than the base case value. Prices increase almost immediately, in 2006 because of the opportunity cost of bankable CO_2 allowances (Figure C-14). The assumed carbon tax is effective in reducing CO_2 production. The shift from coal and less efficient gas-fired capacity to wind, solar and more efficient gas capacity rapidly reduces the CO_2 production factor. The 2025 WECC system wide CO_2 production factor is 0.264 $lbCO_2/kWh$, 48 percent lower than the base case value. Cumulative CO_2 production for the WECC area for the period 2005 - 25 is reduced by 31 percent from the base case forecast.

Because this case is a sensitivity analysis rather than a scenario, the results should be used with caution. If this case were cast as a scenario, other adjustments to assumptions would have to be included. For example, natural gas prices could be expected to increase more rapidly as a result of increased development of gas-fired generating capacity. Electrical loads could be expected to moderate as a result of higher prices and additional conservation would become cost-effective. Wind resources in addition to those included in these model runs might be available, though probably at higher cost than those currently represented. New nuclear resources are not included; it is possible that new-generation modular nuclear plants might produce electricity at lower cost than the marginal resources of this case.

Price Cap

Following a year of extraordinarily high electricity prices, the FERC implemented a floating WECC wholesale trading electricity price cap in June 2001. The original cap triggered when California demand rose to within 7 percent of supply. The cap itself was set for each occurrence based on the estimated production cost of the most-expensive California plant needed to serve

[1] As a further modeling simplification, the carbon tax was applied to all WECC areas, including British Columbia, Alberta and Baja California.

[2] Massachusetts Institute of Technology. Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal. June 2003.

load. This mitigation system was revised in July 2002 to a fixed cap of $250 per megawatt-hour, effective October 2002.

The base and sensitivity cases assume continuation of the $250/MWh wholesale price cap (year 2000 dollars, escalating with inflation). This cap undercuts several of the higher cost load curtailment and demand response blocks, curtailing peak period prices and reducing generation developed to meet peak period loads.

Table C-3: Base and sensitivity case results

Case	Changes from Base	Mid-Columbia Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC coal (GW)	2025 WECC gas (GW)	2025 WECC wind & solar (GW)	2005-25 WECC CO_2 Production ($MMTCO_2$)	2025 WECC August Reserve Margin (%)	2025 PNW January L/R Balance (aMW)[3]
Base Case (Changes 2005 - 2025 shown in percent)									
Final Base	--	$36.20	$46.18	64.6 (75%)	89.7 (18%)	29.9 (570%)	10321 (154%)	11%	-14
Sensitivity Cases (Changes from base shown in percent)									
Medium-low demand forecast	NPCC Medium-low demand forecast case	$34.30 (-5 %)	$45.03 (-3%)	53.4 (-17 %)	82.0 (-9 %)	31.7 (+6 %)	9084 (-12 %)	18 %	3263
Medium-high demand forecast	NPCC Medium-high demand forecast case	$37.70 (+4 %)	$49.92 (+8 %)	74.6 (+16 %)	98.7 (+10 %)	40.0 (+10 %)	11,562 (+12 %)	6 %	-2808
Low fuel price forecast	NPCC Low fuel price forecast case	$29.80 (-18 %)	$39.47 (-15 %)	37.5 (-42 %)	114.2 (+27 %)	22.4 (-25 %)	9187 (-11 percent)	10 %	-471
High fuel price forecast	NPCC High fuel price forecast case	$39.60 (+9 %)	$57.12 (+24 %)	88.6 (+37 %)	66.1 (-26 %)	33.6 (+4 %)	11,074 (+7 %)	11 %	2356
Non-aggressive CO_2 control	$0.87/T CO_2 mitigation, WA & OR only	$33.90 (-6 %)	$46.64 (+1 %)	84.2 (+30 %)	70.2 (-22 %)	22.2 (-26 %)	11,028 (+7 %)	11 %	477
Aggressive CO_2 control	Immediate $0.87/T CO_2 offset in WA & OR Climate Stewardship Act enacted 2006, Ph I in 2012	$50.10 (+38 %)	$49.46 (+7 %)	34.5 (-47 %)	129.5 (+44 %)	44.8 (+50 %)	7126 (-31 percent)	15 %	2946

[3] Excluding demand response capability.

Appendix C1

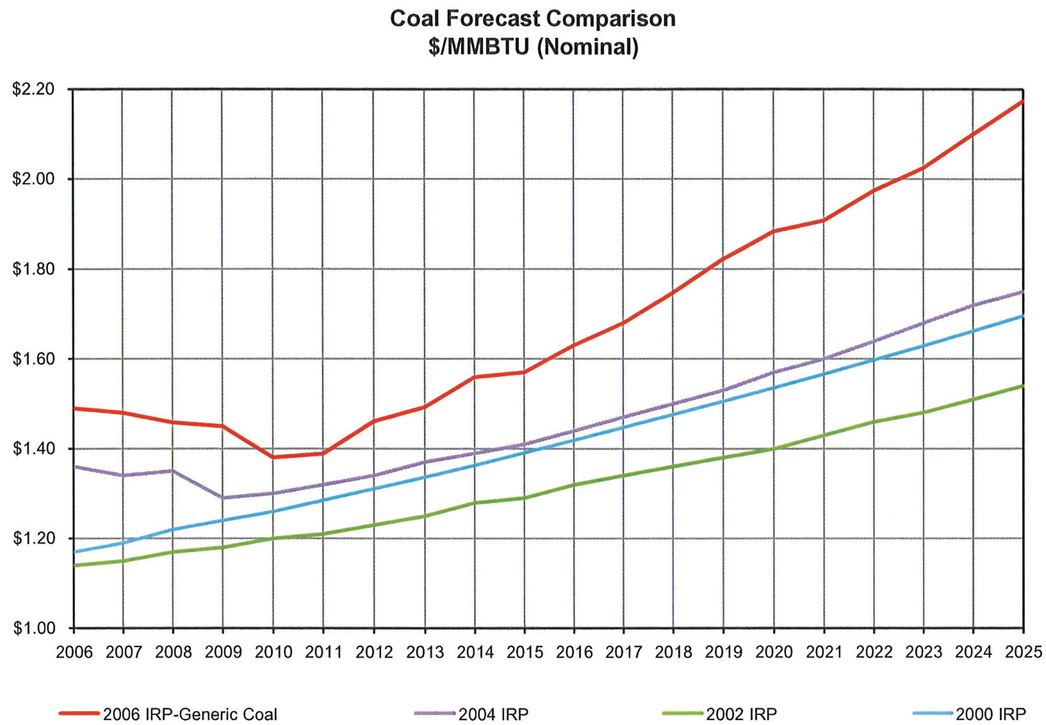
MEMBERS OF THE GENERATING RESOURCES ADVISORY COMMITTEE

Name	Affiliation
Rob Anderson	Bonneville Power Administration
Peter Blood	Calpine Corporation
John Fazio	Northwest Power Planning Council
Stephen Fisher	Mirant Americas Energy Marketing
Mike Hoffman	Bonneville Power Administration
Clint Kalich	Avista Utilities
Eric King	Bonneville Power Administration
Jeff King	Northwest Power Planning Council
Mark Lindberg	Montana Economic Opportunity Office
Bob Looper	Summit Energy, LLC, representing State of Idaho
Jim Maloney	Eugene Water & Electric Board
Dave McClain	D.W. McClain & Associates representing Renewable Northwest Project
Alan Meyer	Weyerhaeuser Corp.
Mike Mikolaitis	Portland General Electric
Bob Neilson	Idaho National Environmental and Engineering Laboratory
Roby Roberts	PacifiCorp Power Marketing
Jim Sanders	Clark Public Utilities
David Stewart-Smith	Oregon Office of Energy
Tony Usibelli	Washington Office of Trade and Economic Development
Carl van Hoff	Energy Northwest
David Vidaver	California Energy Commission
Kevin Watkins	Pacific Northwest Generating Coop
Chris Taylor	Zilkha Renewable Energy

APPENDIX B: SPECIAL STUDY 20.7, ELECTRICITY PRICE DATA

B-2: EXCERPT FROM THE IDAHO POWER COMPANY 2006 INTEGRATED RESOURCE PLAN

		WECC-PNW-IdahoEast		WECC-PNW-IdahoSouth	
Report_Year	Report_Month	Off-Peak WECC	On-Peak WECC	Off-Peak WECC	On-Peak WECC
2016	1	$ 70.17	$ 85.36	$ 67.12	$ 84.18
	2	$ 62.73	$ 79.89	$ 62.28	$ 82.26
	3	$ 56.09	$ 74.35	$ 56.48	$ 77.80
	4	$ 54.06	$ 73.03	$ 52.34	$ 69.64
	5	$ 55.23	$ 74.02	$ 52.93	$ 70.33
	6	$ 55.75	$ 74.86	$ 55.44	$ 71.87
	7	$ 67.62	$ 90.58	$ 66.00	$ 88.25
	8	$ 73.75	$ 99.98	$ 71.34	$ 99.50
	9	$ 62.93	$ 87.32	$ 64.22	$ 89.01
	10	$ 59.97	$ 83.91	$ 59.49	$ 83.90
	11	$ 66.45	$ 84.88	$ 64.93	$ 86.50
	12	$ 69.97	$ 83.81	$ 68.05	$ 83.69
2017	1	$ 75.36	$ 91.06	$ 72.46	$ 90.13
	2	$ 67.54	$ 86.18	$ 67.14	$ 89.20
	3	$ 60.47	$ 80.59	$ 60.41	$ 84.15
	4	$ 59.49	$ 79.19	$ 56.45	$ 75.34
	5	$ 58.77	$ 80.75	$ 56.05	$ 75.31
	6	$ 59.11	$ 80.57	$ 59.56	$ 77.80
	7	$ 71.53	$ 97.99	$ 70.90	$ 97.57
	8	$ 78.83	$ 108.21	$ 76.82	$ 108.02
	9	$ 68.04	$ 94.17	$ 69.63	$ 96.80
	10	$ 64.44	$ 90.35	$ 63.57	$ 90.55
	11	$ 70.87	$ 91.85	$ 68.77	$ 94.16
	12	$ 75.57	$ 90.04	$ 73.39	$ 89.87
2018	1	$ 78.02	$ 94.99	$ 74.93	$ 94.13
	2	$ 70.66	$ 88.93	$ 69.54	$ 92.14
	3	$ 63.84	$ 82.49	$ 63.67	$ 86.38
	4	$ 61.36	$ 82.57	$ 58.74	$ 80.19
	5	$ 60.61	$ 82.28	$ 57.44	$ 76.72
	6	$ 61.05	$ 81.35	$ 60.97	$ 77.78
	7	$ 74.65	$ 100.59	$ 73.27	$ 99.04
	8	$ 81.90	$ 108.67	$ 79.39	$ 108.34
	9	$ 71.47	$ 97.23	$ 72.53	$ 100.69
	10	$ 66.21	$ 92.77	$ 65.37	$ 93.57
	11	$ 74.08	$ 95.36	$ 71.67	$ 98.72
	12	$ 78.28	$ 93.15	$ 76.03	$ 93.03



Coal Forecast Comparison
$/MMBTU (Nominal)
$2.20
$2.00
$1.80
$1.60
$1.40
$1.20
$1.00
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025
2006 IRP-Generic Coal
2004 IRP
2002 IRP
2000 IRP

2006 Integrated Resource Plan

Key Financial and Forecast Assumptions
Resource Cost Analysis

Financing Cap Structure and Cost	
Composition	
Debt	50.54%
Preferred	0.00%
Common	49.46%
Total	100.00%
Cost	
Debt	5.65%
Preferred	0.00%
Common	10.50%
Average Weighted Cost	8.05%

Financial Assumptions and Factors	
Plant Operating (Book) Life	30 Years
Discount Rate (aka WACC)	6.93%
Composite Tax Rate	39.10%
Deferred Rate	35.00%
General O&M Esc Rate	3.00%
Emission Adder Esc Rate	2.26%
Annual Prop Tax Rate (% if Invest)	0.41%
Prop Tax Esc Rate	0.00%
Annual Insurance Prems (% of Invest)	0.25%
Insurance Esc Rate	5.00%
AFUDC Rate (Annual)	6.75%
Prod Tax Credits (First 10 years of operations)	$19/MWh[1]
Prod Tax Credits Esc Rate	3.00%

[1] For those wind and geothermal projects in service by 12-31-2008

Emission Adder Costs (2006 Dollars)	
(adders are brought into the analysis beginning in 2012)	
CO2	$13.62 per ton
NOx	$2,600 per ton during May–September
Mercury	$1,443/oz in years 2012–2017; $1,731/oz in year 2018 and beyond

Emissions Limits (pounds per MWh by technology)

	Pulv. Coal	IGCC	IGCC w/Seq.	CFB Coal	SCCT	CCCT
CO2	1,800	1,717	258	1,800	1,164	822
NOx	0.7	1.1	1.1	1.6	0.2	0.0
Mercury	0.00002	0.00002	0.00002	0.00002	0	0

Fuel Forecast Base Case ($ per MMBTU)						
Year	Gas	Generic Coal[1]	Nuclear	Biomass	Minemouth Wyoming Coal[2]	NW Railed Coal[3]
2006	$8.23	$1.49	$0.40	$2.00	$1.12	$1.74
2007	$8.62	$1.48	$0.40	$2.00	$1.05	$1.79
2008	$8.00	$1.46	$0.40	$2.00	$1.01	$1.79
2009	$7.91	$1.45	$0.40	$2.00	$0.99	$1.79
2010	$5.90	$1.38	$0.40	$2.00	$0.98	$1.72
2011	$5.95	$1.39	$0.40	$2.00	$0.97	$1.74
2012	$6.04	$1.46	$0.40	$2.00	$1.00	$1.86
2013	$6.24	$1.49	$0.40	$2.00	$1.00	$1.92
2014	$6.42	$1.56	$0.40	$2.00	$1.08	$1.98
2015	$6.64	$1.57	$0.40	$2.00	$1.08	$1.99
2016	$6.92	$1.63	$0.40	$2.00	$1.13	$2.07
2017	$7.23	$1.68	$0.40	$2.00	$1.15	$2.14
2018	$7.49	$1.75	$0.40	$2.00	$1.22	$2.20
2019	$7.86	$1.82	$0.40	$2.00	$1.28	$2.30
2020	$8.16	$1.88	$0.40	$2.00	$1.33	$2.37
2021	$7.51	$1.91	$0.40	$2.00	$1.33	$2.42
2022	$7.79	$1.97	$0.40	$2.00	$1.37	$2.51
2023	$8.14	$2.03	$0.40	$2.00	$1.39	$2.60
2024	$8.38	$2.10	$0.40	$2.00	$1.45	$2.69
2025	$8.70	$2.17	$0.40	$2.00	$1.50	$2.78
2026	$8.09	$2.25	$0.40	$2.00	$1.55	$2.88
2027	$8.44	$2.67	$0.40	$2.00	$1.44	$3.78
2028	$8.75	$2.78	$0.40	$2.00	$1.49	$3.94
2029	$9.08	$2.89	$0.40	$2.00	$1.53	$4.11
2030	$9.48	$3.00	$0.40	$2.00	$1.58	$4.29
2031	$9.61	$3.21	$0.40	$2.00	$1.64	$4.65
2032	$9.74	$3.34	$0.40	$2.00	$1.69	$4.86
2033	$9.88	$3.47	$0.40	$2.00	$1.74	$5.07
2034	$10.01	$3.62	$0.40	$2.00	$1.80	$5.31
2035	$10.14	$3.77	$0.40	$2.00	$1.86	$5.54

[1] Used to estimate costs in the resource stack for the southern Idaho pulverized coal resource.

[2] Used to estimate costs in the resource stack for the Wyoming pulverized coal resource.

[3] Used to estimate costs in the resource stack for the regional pulverized, regional fluidized bed, regional IGCC with carbon sequestration, and regional IGCC coal projects.

2006 Integrated Resource Plan
Cost Inputs and Operating Assumptions Resource Cost Analysis
(All Costs in 2006 Dollars)

Supply Side Resources	Plant Capital $/kW [1,3]	Interconnection Capital $/kW [4]	Total Capital $/kW	Total Investment $/kW [2]	Fixed O&M $/kW	Variable O&M $/MWh	Emissions $/MWh [7]	Heat Rate
Industrial Simple Cycle CT (170 MW)	$435	$50	$485	$503	$6.96	$4.64	$8.03	10,500
Combined Cycle CT (225 MW)	$655	$38	$693	$732	$10.26	$3.25	$5.60	7,030
Aeroderivative Simple Cycle CT (47 MW)	$696	$69	$765	$793	$9.27	$9.27	$8.03	9,960
Combined Heat and Power (100 MW)	$902	$60	$962	$998	$7.24	$4.77	$0.00	5,000
Wind (100 MW)	$1,500	$110	$1,610	$1,675	$23.19	$1.16	$0.00	NA
South Idaho Pulverized Coal (600 MW)	$1,596	$42	$1,638	$1,825	$19.50	$2.58	$13.08	8,957
Regional Pulverized Coal (600 MW)	$1,596	$317	$1,913	$2,131	$19.50	$2.58	$13.08	8,957
Wyoming Pulverized Coal (600 MW)	$1,596	$317	$1,913	$2,131	$19.50	$2.58	$13.08	8,957
Small Hydro Existing Facility (10 MW)	$1,880	$60	$1,940	$2,085	$15.21	$3.23	$0.00	NA
Regional Fluidized Bed Coal (600 MW)	$1,734	$317	$2,051	$2,285	$21.35	$3.08	$13.59	9,208
Advanced Nuclear (1,000 MW)	$2,137	$34	$2,171	$2,491	$65.58	$0.48	$0.00	10,400
Geothermal Flash Steam	$2,121	$130	$2,251	$2,420	$111.29	$0.00	$0.00	NA
Regional IGCC (600 MW)	$1,974	$317	$2,291	$2,640	$22.62	$2.68	$12.75	8,131
Wood Residue Biomass (25 MW)	$2,319	$130	$2,449	$2,553	$92.74	$10.43	$0.00	14,500
Regional IGCC with Carbon Sequest. (600 MW)	$2,369	$317	$2,686	$2,993	$27.14	$3.21	$2.53	8,400
Small Hydro New Facility (10 MW)	$3,093	$60	$3,153	$3,389	$15.21	$3.23	$0.00	NA
Solar Thermal (100 MW)	$3,233	$110	$3,343	$3,503	$54.85	$0.00	$0.00	NA
Geothermal Binary Cycle (50 MW)	$3,184	$220	$3,404	$3,706	$124.00	$1.80	$0.00	NA
Solar Photovoltaic (5 MW)	$4,878	$60	$4,938	$5,130	$11.29	$0.00	$0.00	NA

Transmission Plus Market Purchase Alternatives	Capital $/kW [1,2]	Interconnection $/kW	Total Capital $/kW	Total Investment $/kW	Fixed O&M $/kW [6]	Market Purchase $/MWh [5]	Emissions $/MWh	Heat Rate
Transmission–From NW Lolo to IPC System (60 MW)	$179	NA	$179	$197	$1.00	$60.00	NA	NA
Transmission–From Wyoming to IPC System (900 MW)	$313	NA	$313	$351	$0.20	$60.00	NA	NA
Transmission–From NW McNary to IPC System (225 MW)	$340	NA	$340	$373	$0.39	$60.00	NA	NA
Transmission–From Wyoming to IPC System (525 MW)	$362	NA	$362	$406	$0.20	$60.00	NA	NA
Transmission–From Wyoming to Boise (900 MW)	$407	NA	$407	$457	$0.20	$60.00	NA	NA
Transmission–From Wyoming to Boise (525 MW)	$482	NA	$482	$540	$0.20	$60.00	NA	NA
Transmission–From NW McNary to Boise (225 MW)	$546	NA	$546	$600	$0.39	$60.00	NA	NA
Transmission–From Montana to IPC System (225 MW)	$694	NA	$694	$783	$0.31	$60.00	NA	NA
Transmission–From Montana to Boise (225 MW)	$788	NA	$788	$889	$0.20	$60.00	NA	NA
Transmission–From Wyoming to IPC System (225 MW)	$844	NA	$844	$947	$0.20	$60.00	NA	NA
Transmission–From Nevada South to IPC System (225 MW)	$851	NA	$851	$959	$0.38	$60.00	NA	NA
Transmission–From Wyoming to Boise (225 MW)	$939	NA	$939	$1,053	$0.31	$60.00	NA	NA
Transmission–From Nevada South to Boise (225 MW)	$945	NA	$945	$1,066	$0.38	$60.00	NA	NA
Transmission–From NW Lolo to Boise (60 MW)	$953	NA	$953	$1,046	$1.00	$60.00	NA	NA

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Cost inputs and operating assumptions based on estimates from the Northwest Power Planning Council's Fifth Power Plan, The Department of Energy's 2006 Energy Outlook, independent consultant data, and independent power developers.
[4] Assumes a generic transmission interconnection consisting of a substation at a power plant, radial transmission line , and termination at IPC system. Power plant substation: $4M to $10M, Radial line: $200K–550K per mile depending on rating (69kV, 138kV, 230kV, 3445kV), Termination at IPC System: $200K–$1M Assumes resources sited within 25 miles of IPC's system with the exception of regional coal and Wyoming coal resources.
[5] Transmission plus market purchase alternatives assume a transmission upgrade, with a market purchase of $60 per MWh.
[6] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)
[7] Emission adders assume CO_2 at $13.62/ton; NO_x at $2,600/ton; mercury at $1,443/oz.

Levelized Resource Cost Tables

Energy—Levelized Cost per MWh

At Estimated Annual Capacity Factors (Baseload Service)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Cost per MWh	Capacity Factor
Geothermal Flash Steam with PTC (50 MW)	$26	$9	$0	$0	$35	95%
Geothermal Flash Steam without PTC (50 MW)	$26	$22	$0	$0	$47	95%
Advanced Nuclear (1,000 MW)	$33	$15	$4	$0	$53	90%
Small Hydro Existing Facility (10 MW)	$41	$12	$0	$0	$53	60%
Geothermal Binary Cycle with PTC (50 MW)	$40	$15	$0	$0	$55	95%
Combined Heat and Power (100 MW)	$13	$9	$38	$0	$60	90%
Wind with PTC (100 MW)	$54	$6	$0	$0	$61	31%
Wyoming Pulverized Coal (600 MW)	$29	$10	$11	$12	$61	88%
Regional Pulverized Coal (600 MW)	$29	$10	$17	$12	$67	88%
Geothermal Binary Cycle without PTC (50 MW)	$40	$28	$0	$0	$67	95%
South Idaho Pulverized Coal (600 MW)	$25	$9	$22	$12	$67	88%
Regional Fluidized Bed Coal (600 MW)	$31	$11	$17	$12	$71	88%
Wind without PTC (100 MW)	$54	$19	$0	$0	$73	31%
Regional IGCC with Carbon Sequest. (600 MW)	$45	$14	$16	$2	$76	80%
Regional IGCC (600 MW)	$39	$12	$15	$11	$78	80%
Combined Cycle CT (225 MW)	$10	$7	$55	$5	$78	85%
Small Hydro New Facility (10 MW)	$67	$14	$0	$0	$81	60%
Wood Residue Biomass (25 MW)	$32	$37	$30	$0	$99	80%
Industrial Simple Cycle CT (170 MW)	$10	$9	$83	$7	$109	59%
Aeroderivative Simple Cycle CT (47 MW)	$15	$17	$78	$7	$118	59%
Solar Thermal (100 MW)	$85	$34	$0	$0	$118	42%
Solar Photovoltaic (5 MW)	$174	$23	$0	$0	$197	30%

Transmission Plus Market Purchase Alternatives	Cost of Capital	Non-Fuel O&M	Energy	Emission Adders	Cost per MWh	Capacity Factor
Transmission–From NW Lolo to IPC System (60 MW)	$4	$1	$60	$0	$64	61%
Transmission–From Wyoming to IPC System (900 MW)	$7	$1	$60	$0	$67	61%
Transmission–From NW McNary to IPC System (225 MW)	$7	$1	$60	$0	$68	61%
Transmission–From Wyoming to IPC System (525 MW)	$8	$1	$60	$0	$68	61%
Transmission–From Wyoming to Boise (900 MW)	$9	$1	$60	$0	$69	61%
Transmission–From Wyoming to Boise (525 MW)	$10	$1	$60	$0	$71	61%
Transmission–From NW McNary to Boise (225 MW)	$11	$1	$60	$0	$72	61%
Transmission–From Montana to IPC System (225 MW)	$15	$1	$60	$0	$76	61%
Transmission–From Montana to Boise (225 MW)	$17	$1	$60	$0	$78	61%
Transmission–From Wyoming to IPC System (225 MW)	$18	$2	$60	$0	$79	61%
Transmission–From Nevada South to IPC System (225 MW)	$18	$2	$60	$0	$80	61%
Transmission–From Wyoming to Boise (225 MW)	$20	$2	$60	$0	$82	61%
Transmission–From NW Lolo to Boise (60 MW)	$20	$2	$60	$0	$82	61%
Transmission–From Nevada South to Boise (225 MW)	$20	$2	$60	$0	$82	61%

DSM Programs	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Cost per MWh	Capacity Factor
Commercial In-Place Construction (18 aMW)	$0	$35	$0	$0	$35	NA
Industrial Efficiency Expansion (41 aMW)	$0	$40	$0	$0	$40	NA
Residential In-Place Construction (29 aMW)	$0	$44	$0	$0	$44	NA

Levelized Resource Cost Tables

Energy—Levelized Cost per MWh

At Peaking Service Capacity Factors **

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Cost per MWh	Capacity Factor
Industrial Simple Cycle CT (170 MW)	$154	$50	$83	$7	$293	4%
Combined Cycle CT (225 MW)	$224	$68	$55	$5	$352	4%
Aeroderivative Simple Cycle CT (47 MW)	$242	$74	$78	$7	$402	4%
Combined Heat and Power (100 MW)	$305	$64	$38	$0	$407	4%
Wind with PTC (100 MW)	$452	$133	$0	$0	$585	4%
Wind without PTC (100 MW)	$452	$146	$0	$0	$598	4%
South Idaho Pulverized Coal (600 MW)	$579	$136	$22	$12	$748	4%
Small Hydro Existing Facility (10 MW)	$661	$125	$0	$0	$787	4%
Wyoming Pulverized Coal (600 MW)	$676	$144	$11	$12	$843	4%
Regional Pulverized Coal (600 MW)	$676	$144	$17	$12	$849	4%
Regional Fluidized Bed Coal (600 MW)	$725	$157	$17	$12	$911	4%
Regional IGCC (600 MW)	$838	$171	$15	$11	$1,035	4%
Advanced Nuclear (1,000 MW)	$790	$349	$4	$0	$1,144	4%
Regional IGCC with Carbon Sequest. (600 MW)	$949	$201	$16	$2	$1,168	4%
Geothermal Flash Steam with PTC (50 MW)	$653	$531	$0	$0	$1,183	4%
Geothermal Flash Steam without PTC (50 MW)	$653	$543	$0	$0	$1,196	4%
Wood Residue Biomass (25 MW)	$688	$482	$30	$0	$1,200	4%
Small Hydro New Facility (10 MW)	$1,075	$160	$0	$0	$1,235	4%
Solar Thermal (100 MW)	$945	$375	$0	$0	$1,320	4%
Solar Photovoltaic (5 MW)	$1,384	$185	$0	$0	$1,568	4%
Geothermal Binary Cycle with PTC (50 MW)	$1,000	$622	$0	$0	$1,622	4%
Geothermal Binary Cycle without PTC (50 MW)	$1,000	$635	$0	$0	$1,635	4%

Transmission Plus Market Purchase Alternatives	Cost of Capital	Non-Fuel O&M	Energy	Emission Adders	Cost per MWh	Capacity Factor
Transmission–From NW Lolo to IPC System (60 MW)	$60	$9	$60	$0	$130	4%
Transmission–From Wyoming to IPC System (900 MW)	$101	$9	$60	$0	$171	4%
Transmission–From NW McNary to IPC System (225 MW)	$115	$11	$60	$0	$186	4%
Transmission–From Wyoming to IPC System (525 MW)	$117	$11	$60	$0	$188	4%
Transmission–From Wyoming to Boise (900 MW)	$132	$12	$60	$0	$204	4%
Transmission–From Wyoming to Boise (525 MW)	$156	$14	$60	$0	$230	4%
Transmission–From NW McNary to Boise (225 MW)	$184	$17	$60	$0	$261	4%
Transmission–From Montana to IPC System (225 MW)	$240	$21	$60	$0	$322	4%
Transmission–From Montana to Boise (225 MW)	$273	$24	$60	$0	$356	4%
Transmission–From Wyoming to IPC System (225 MW)	$291	$25	$60	$0	$376	4%
Transmission–From Nevada South to IPC System (225 MW)	$294	$26	$60	$0	$381	4%
Transmission–From Wyoming to Boise (225 MW)	$323	$28	$60	$0	$411	4%
Transmission–From NW Lolo to Boise (60 MW)	$321	$31	$60	$0	$412	4%
Transmission–From Nevada South to Boise (225 MW)	$327	$29	$60	$0	$416	4%

** 330 Annual Operating Hours Assumed for Peaking Service (Approximately 4% of Total Hours)

Levelized Resource Cost Tables

Capacity—Levelized Cost per kW per Month
Cost of Capital and Fixed Operating Costs

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Industrial Simple Cycle CT (170 MW)	$4	$1	$0	$0	$5
Combined Cycle CT (225 MW)	$6	$2	$0	$0	$8
Aeroderivative Simple Cycle CT (47 MW)	$7	$2	$0	$0	$8
Combined Heat and Power (100 MW)	$8	$2	$0	$0	$10
South Idaho Pulverized Coal (600 MW)	$16	$4	$0	$0	$20
Small Hydro Existing Facility (10 MW)	$18	$3	$0	$0	$22
Wyoming Pulverized Coal (600 MW)	$19	$4	$0	$0	$22
Regional Pulverized Coal (600 MW)	$19	$4	$0	$0	$22
Regional Fluidized Bed Coal (600 MW)	$20	$4	$0	$0	$24
Regional IGCC (600 MW)	$23	$5	$0	$0	$28
Advanced Nuclear (1,000 MW)	$22	$10	$0	$0	$31
Regional IGCC with Carbon Sequest. (600 MW)	$26	$5	$0	$0	$32
Wood Residue Biomass (25 MW)	$19	$13	$0	$0	$32
Geothermal Flash Steam (50 MW)	$18	$15	$0	$0	$33
Small Hydro New Facility (10 MW)	$30	$4	$0	$0	$34
Solar Thermal (100 MW)	$26	$10	$0	$0	$36
Solar Photovoltaic (5 MW)	$38	$5	$0	$0	$43
Geothermal Binary Cycle (50 MW)	$28	$17	$0	$0	$45
Wind (100 MW Nameplate; 5 MW On Peak)	$249	$79	$0	$0	$328

Transmission Plus Market Purchase Alternatives	Cost of Capital	Non-Fuel O&M	Energy	Emission Adders	Total
Transmission–From NW Lolo to IPC System (60 MW)	$2	$0	$0	$0	$2
Transmission–From Wyoming to IPC System (900 MW)	$3	$0	$0	$0	$3
Transmission–From NW McNary to IPC System (225 MW)	$3	$0	$0	$0	$3
Transmission–From Wyoming to IPC System (525 MW)	$3	$0	$0	$0	$4
Transmission–From Wyoming to Boise (900 MW)	$4	$0	$0	$0	$4
Transmission–From Wyoming to Boise (525 MW)	$5	$0	$0	$0	$5
Transmission–From NW McNary to Boise (225 MW)	$5	$0	$0	$0	$6
Transmission–From Montana to IPC System (225 MW)	$7	$1	$0	$0	$7
Transmission–From Montana to Boise (225 MW)	$8	$1	$0	$0	$8
Transmission–From Wyoming to IPC System (225 MW)	$8	$1	$0	$0	$9
Transmission–From Nevada South to IPC System (225 MW)	$8	$1	$0	$0	$9
Transmission–From Wyoming to Boise (225 MW)	$9	$1	$0	$0	$10
Transmission–From NW Lolo to Boise (60 MW)	$9	$1	$0	$0	$10
Transmission–From Nevada South to Boise (225 MW)	$9	$1	$0	$0	$10

DSM Programs	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Residential In-Place Construction (111 MW Peak)	$0	$6	$0	$0	$6
Industrial Efficiency Expansion (49 MW Peak)	$0	$13	$0	$0	$13
Commercial In-Place Construction (27 MW Peak)	$0	$14	$0	$0	$14

2006 Integrated Resource Plan
Cost Inputs Used for Resource Cost Analysis
(All Costs in 2006 Dollars)

	Plant $/kW	Interconnection $/kW	Total $/kW	Cap Factor	Fixed O&M $/kW	Variable O&M $/MWh	Emissions $/MWh	Heat Rate
Supply Side Resources								
Industrial Simple Cycle CT (162 MW)	$435	$94	$529	59%	$6.96	$4.64	$8.03	10,500
CCCT (540 MW)	$655	$71	$726	85%	$10.26	$3.25	$5.60	7,030
Aero Simple Cycle CT (47 MW)	$696	$60	$756	59%	$9.27	$9.27	$8.03	9,960
Combined Heat and Power (6 MW)	$902	$60	$962	90%	$7.24	$4.77	$0.00	5,000
Wind (100 MW)	$1,500	$110	$1,610	31%	$23.19	$1.16	$0.00	NA
South Idaho Pulverized Coal (600 MW)	$1,596	$42	$1,638	88%	$19.50	$2.58	$12.62	8,957
Advanced Nuclear (1,100 MW)	$2,137	$63	$2,200	90%	$65.58	$0.49	$0.00	10,400
Regional Pulverized Coal (600 MW)	$1,596	$317	$1,913	88%	$19.50	$2.58	$12.62	8,957
Wyoming Pulverized Coal (575 MW)	$1,596	$330	$1,926	88%	$19.50	$2.58	$12.62	8,957
Small Hydro Existing Facility (10 MW)	$1,880	$60	$1,940	60%	$15.21	$3.23	$0.00	NA
Regional Fluidized Bed Coal (600 MW)	$1,734	$317	$2,051	88%	$21.35	$3.08	$13.12	9,208
Regional IGCC (600 MW)	$1,974	$317	$2,291	80%	$22.62	$2.68	$12.29	8,131
Geothermal Flash Steam	$2,121	$220	$2,341	95%	$111.29	$0.00	$0.00	NA
Wood Residue Biomass (25 MW)	$2,319	$60	$2,379	80%	$92.74	$10.43	$0.00	14,500
Regional IGCC with Carbon Sequest. (600 MW)	$2,369	$317	$2,686	80%	$27.14	$3.21	$2.07	8,400
Geothermal Binary Cycle (50 MW)	$3,184	$220	$3,404	95%	$132.00	$1.80	$0.00	NA
Small Hydro New Facility (10 MW)	$3,093	$60	$3,153	60%	$15.21	$3.23	$0.00	NA
Solar Thermal (100 MW)	$3,233	$60	$3,293	42%	$54.89	$0.00	$0.00	NA
Solar Photovoltaic (5 MW)	$4,878	$60	$4,938	30%	$11.30	$0.00	$0.00	NA
Transmission Plus Market Purchase Alternatives								
Transmission–From NW Lolo to IPC System (60 MW)	$179	$0	$179	61%	$1.00	$60.00	$0.00	NA
Transmission–From NW McNary to IPC System (180 MW)	$424	$0	$424	61%	$0.39	$60.00	$0.00	NA
Transmission–From Montana to IPC System (225 MW)	$694	$0	$694	61%	$0.31	$60.00	$0.00	NA
Transmission–From NW McNary to Boise (180 MW)	$706	$0	$706	61%	$0.39	$60.00	$0.00	NA
Transmission–From Montana to Boise (225 MW)	$788	$0	$788	61%	$0.20	$60.00	$0.00	NA
Transmission–From Wyoming to IPC System (225 MW)	$844	$0	$844	61%	$0.20	$60.00	$0.00	NA
Transmission–From Nevada South to IPC System (225 MW)	$851	$0	$851	61%	$0.38	$60.00	$0.00	NA
Transmission–From Wyoming to Boise (225 MW)	$939	$0	$939	61%	$0.31	$60.00	$0.00	NA
Transmission–From Nevada South to Boise (225 MW)	$945	$0	$945	61%	$0.38	$60.00	$0.00	NA
Transmission–From NW Lolo to Boise (60 MW)	$953	$0	$953	61%	$1.00	$60.00	$0.00	NA

Notes

1. Plant costs include engineering development costs, generating and ancilary equipment purchase and installation costs, as well as balance of plant construction.
2. Cost inputs and operating assumptions based on estimates from the Northwest Power Planning Council's Fifth Power Plan, The Department of Energy's 2006 Energy Outlook, independent consultant data, and independent power developers.
3. All capital costs are shown before AFUDC and investment tax credits are applied.
4. Assumes a generic transmission interconnection consisting of a substation at a power plant, radial transmission line, and termination at IPC system.
   Power plant substation: $4M to $10M, Radial line: $200K–550K per mile depending on rating (69kV, 138kV, 230kV, 3445kV), Termination at IPC System: $200K–$1M
   Assumes resources sited within 25 miles of IPC's system with the exception of regional and Wyoming coal resources.
   Transmission plus market purchase alternatives assume a general transmission upgrade, with a market purchase of $60 per MWh at the end.

Levelized Resource Cost Tables

Energy–Levelized Cost per Mwh

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Geothermal Flash Steam with PTC (50 MW)	26.91	9.15	0.00	0.00	36.06
Geothermal Flash Steam without PTC (50 MW)	26.91	21.65	0.00	0.00	48.56
Advanced Nuclear (1,100 MW)	33.52	15.32	4.41	0.00	53.24
Small Hydro Existing Facility (10 MW)	41.25	12.12	0.00	0.00	53.38
Geothermal Binary Cycle with PTC (50 MW)	39.66	16.49	0.00	0.00	56.15
Combined Heat and Power (6 MW)	12.75	9.19	38.20	0.00	60.15
Wind with PTC (100 MW)	54.34	6.49	0.00	0.00	60.83
Wyoming Pulverized Coal (575 MW)	28.95	9.68	11.04	11.25	60.92
Regional Pulverized Coal (600 MW)	28.95	9.68	16.77	11.25	66.64
South Idaho Pulverized Coal (600 MW)	24.78	9.33	21.70	11.25	67.06
Geothermal Binary Cycle without PTC (50 MW)	39.66	28.99	0.00	0.00	68.65
Regional Fluidized Bed Coal (600 MW)	31.03	10.91	17.24	11.70	70.87
Wind without PTC (100 MW)	54.34	18.99	0.00	0.00	73.33
Regional IGCC with Carbon Sequest. (600 MW)	44.71	13.80	15.72	1.84	76.07
CCCT (540 MW)	10.38	7.47	53.71	4.99	76.56
Regional IGCC (600 MW)	39.44	11.68	15.22	10.95	77.29
Small Hydro New Facility (10 MW)	67.05	14.28	0.00	0.00	81.33
Wood Residue Biomass (25 MW)	31.49	36.72	29.99	0.00	98.20
Industrial Simple Cycle CT (162 MW)	10.71	9.43	80.23	7.16	107.53
Aero Simple Cycle CT (47 MW)	15.31	17.06	76.10	7.16	115.62
Solar Thermal (100 MW)	83.48	33.53	0.00	0.00	117.02
Solar Photovoltaic (5 MW)	173.73	23.19	0.00	0.00	196.93

Transmission Plus Market Purchase Alternatives	Cost of Capital	Non-Fuel O&M	Energy	Emission Adders	Total
Transmission–From NW Lolo to IPC System (60 MW)	3.73	0.57	60.00	0.00	64.30
Transmission–From NW McNary to IPC System (180 MW)	8.84	0.84	60.00	0.00	69.67
Transmission–From NW McNary to Boise (180 MW)	14.70	1.33	60.00	0.00	76.03
Transmission–From Montana to IPC System (225 MW)	14.84	1.32	60.00	0.00	76.16
Transmission–From Montana to Boise (225 MW)	16.85	1.46	60.00	0.00	78.30
Transmission–From Wyoming to IPC System (225 MW)	17.94	1.55	60.00	0.00	79.49
Transmission–From Nevada South to IPC System (225 MW)	18.19	1.62	60.00	0.00	79.80
Transmission–From Wyoming to Boise (225 MW)	19.95	1.75	60.00	0.00	81.70
Transmission–From NW Lolo to Boise (60 MW)	19.83	1.91	60.00	0.00	81.74
Transmission–From Nevada South to Boise (225 MW)	20.20	1.79	60.00	0.00	81.99

DSM Programs	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Commercial In-Place Construction (18 aMW)	0.00	34.90	0.00	0.00	34.90
Industrial Efficiency Expansion (41 aMW)	0.00	39.70	0.00	0.00	39.70
Residential In-Place Construction (29 aMW)	0.00	43.89	0.00	0.00	43.89

Levelized Resource Cost Tables

Capacity– Levelized $/kW/month

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Industrial Simple Cycle CT (162 MW)	4.61	1.22	0.00	0.00	5.83
CCCT (540 MW)	6.44	1.77	0.00	0.00	8.22
Aero Simple Cycle CT (47 MW)	6.58	1.67	0.00	0.00	8.25
Combined Heat and Power (6 MW)	8.38	1.58	0.00	0.00	9.96
Wind (100 MW)	12.43	3.97	0.00	0.00	16.40
South Idaho Pulverized Coal (600 MW)	15.92	3.64	0.00	0.00	19.56
Small Hydro Existing Facility (10 MW)	18.19	3.32	0.00	0.00	21.51
Regional Pulverized Coal (600 MW)	18.59	3.86	0.00	0.00	22.46
Wyoming Pulverized Coal (575 MW)	18.60	3.86	0.00	0.00	22.46
Regional Fluidized Bed Coal (600 MW)	19.93	4.19	0.00	0.00	24.13
Regional IGCC (600 MW)	23.03	4.60	0.00	0.00	27.63
Wood Residue Biomass (25 MW)	18.39	12.79	0.00	0.00	31.18
Regional IGCC with Carbon Sequest. (600 MW)	26.11	5.40	0.00	0.00	31.51
Advanced Nuclear (1,100 MW)	22.02	9.61	0.00	0.00	31.63
Geothermal Flash Steam (50 MW)	18.67	15.01	0.00	0.00	33.68
Small Hydro New Facility (10 MW)	29.56	4.27	0.00	0.00	33.83
Solar Thermal (100 MW)	25.60	10.28	0.00	0.00	35.88
Solar Photovoltaic (5 MW)	38.05	5.08	0.00	0.00	43.13
Geothermal Binary Cycle (50 MW)	27.51	18.33	0.00	0.00	45.84

Transmission Plus Market Purchase Alternatives	Cost of Capital	Non-Fuel O&M	Energy	Emission Adders	Total
Transmission–From NW Lolo to IPC System (60 MW)	1.66	0.25	0.00	0.00	1.91
Transmission–From NW McNary to IPC System (180 MW)	3.93	0.37	0.00	0.00	4.31
Transmission–From NW McNary to Boise (180 MW)	6.54	0.59	0.00	0.00	7.14
Transmission–From Montana to IPC System (225 MW)	6.61	0.59	0.00	0.00	7.20
Transmission–From Montana to Boise (225 MW)	7.50	0.65	0.00	0.00	8.15
Transmission–From Wyoming to IPC System (225 MW)	7.99	0.69	0.00	0.00	8.68
Transmission–From Nevada South to IPC System (225 MW)	8.10	0.72	0.00	0.00	8.82
Transmission–From Wyoming to Boise (225 MW)	8.89	0.78	0.00	0.00	9.66
Transmission–From NW Lolo to Boise (60 MW)	8.83	0.85	0.00	0.00	9.68
Transmission–From Nevada South to Boise (225 MW)	9.00	0.80	0.00	0.00	9.79

DSM Programs	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total
Commercial In-Place Construction (34 MW Peak)	0.00	13.63	0.00	0.00	13.63
Industrial Efficiency Expansion (76 MW Peak)	0.00	15.50	0.00	0.00	15.50
Residential In-Place Construction (55 MW Peak)	0.00	16.66	0.00	0.00	16.66

APPENDIX B: SPECIAL STUDY 20.7, ELECTRICITY PRICE DATA

B-3: E-MAIL FROM KARL BOKENKAMP OF IDAHO POWER COMPANY

Bolthrunis, Charles

From: Dan Mears [mears@ti-sd.com]
Sent: Thursday, December 14, 2006 2:29 PM
To: Bolthrunis, Charles
Cc: Brabazon, Edward
Subject: Fwd: Idaho Power's 2006 IRP
Follow Up Flag: Follow up
Flag Status: Completed

X-AntiVirus: Skipped; prescanned by simscan
X-Final-Delivery: delta.postal.redwire.net v8.6.8; msgid 200612-1322589-4003551
X-Spam-Checker-Version: SpamAssassin 3.1.7 (2006-10-05) on
delta.postal.redwire.net
X-Spam-Level: *
X-Spam-Status: No, score=1.6 required=5.0 tests=DK_POLICY_SIGNSOME,
HTML_MESSAGE,SMALLFONT_DIV2 autolearn=disabled version=3.1.7
Delivered-To: mears@redwire.net
Delivered-To: mears@ti-sd.com
X-Server-Uuid: BE314DA1-B455-4CC7-95DE-AD100FF77B6E
Subject: Idaho Power's 2006 IRP
Date: Thu, 14 Dec 2006 11:00:43 -0700
X-MS-Has-Attach:
X-MS-TNEF-Correlator:
Thread-Topic: Idaho Power's 2006 IRP
Thread-Index: AccfqcXRZpmUliYMSk2PunHHJOPM9A==
From: "Bokenkamp, Karl" <KBokenkamp@idahopower.com>
To: mears@ti-sd.com
X-WSS-ID: 699F4C121UG473838-01-01

Dan - Here's a link to our 2006 IRP:

http://www.idahopower.com/energycenter/irp/2006/2006IRPFinal.htm

Go to appendix D - pages 60 through 62 of the pdf (pages 51, 52 and 53 of the appendix) for the financial assumptions, gas forecasts and the estimated capital and O&M costs for a number of resources resources in 2006$. The next few pages provide levelized costs for the resources. I hope this helps. It will take me a little longer to round up the other data. If you have any questions, feel free to give me a call at 208-388-2482.
Karl

==

"EMF <idahopower.com>" made the previous
annotations.

+++++++++++++++++++++++++++++

Dan Mears, President
Technology Insights
6540 Lusk Blvd., C-102
San Diego, CA 92121-2767
Tel: 858-455-9500
FAX: 858-452-7831
Web: http://www.technologyinsights.com

APPENDIX C: SPECIAL STUDY 20.7, REVISED SLIDES FROM MEETING OF DECEMBER 6, 2006

NGNP By-Products Study
Special Study No. 20.7

December 6, 2006

Revised 1/4/2007

Objectives

- **Size for demonstration of commercial feasibility**
  - ➡ Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- **Identify product and by-product markets**
- **Identify additional processing requirements**
- **Identify waste streams and disposal means**

Demonstration Criteria

- **Must demonstrate:**
  - Transport phenomena at or near full scale
  - Reaction kinetics with commercially manufactured catalyst
  - Integrated operation at a scale that provides confidence that a commercial installation will operate similarly
  - Long-term operability with commercially available feedstocks
  - Manufacturability of commercial scale equipment using commercially available materials of construction
  - Equipment durability and satisfactory long-term operation
  - A reasonable basis for estimating equipment and operating costs

Smallest Required Hydrogen Plant

- **Set by a critical piece of equipment which may be different for each technology:**
  - That piece of equipment which sets the maximum capacity of the plant when designed for the minimum size to fulfill the demonstration requirements
  - High-temperature Electrolysis (HTE)
    - ***Recuperators***
    - ***Steam Generator and Superheater***
  - Hybrid Sulfur (HyS)
    - ***Sulfuric Acid and Sulfur Trioxide decomposition reactor(s)***
  - Sulfur Iodine (SI)
    - ***Sulfuric Acid and Sulfur Trioxide decomposition reactor(s)***
    - ***Reactive Distillation column***

Smallest Required HTE Hydrogen Plant

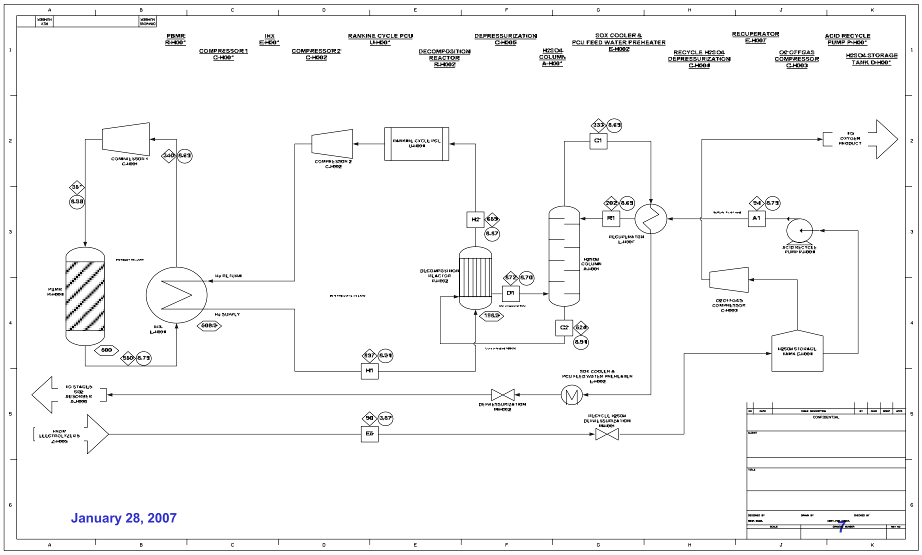
- **Superheater is the most challenging PCHX; 2.9 MW is equivalent to approximately a 100 tube unit.**
  - Work based on: **Richards, M.B., et. al., <u>H2-MHR Pre-conceptual Design Report: HTE-based Plant</u>**, US DOE Contract No. DE-FG03-02SF22609/A000, GA-A25402, April 2006)
  - O_2 and H_2 Recuperators
    - ***Too complex for a single unit***
    - ***Recuperation is enhancing, not enabling***
  - Process-coupling heat exchangers (PCHXs) Steam Generator and Superheater
    - ***Not complex***
  - Preliminary sizing carried out on all exchangers

Smallest Required HTE Hydrogen Plant Equipment Sizes

- **Proportioned to the 2.9 MWth Superheater:**

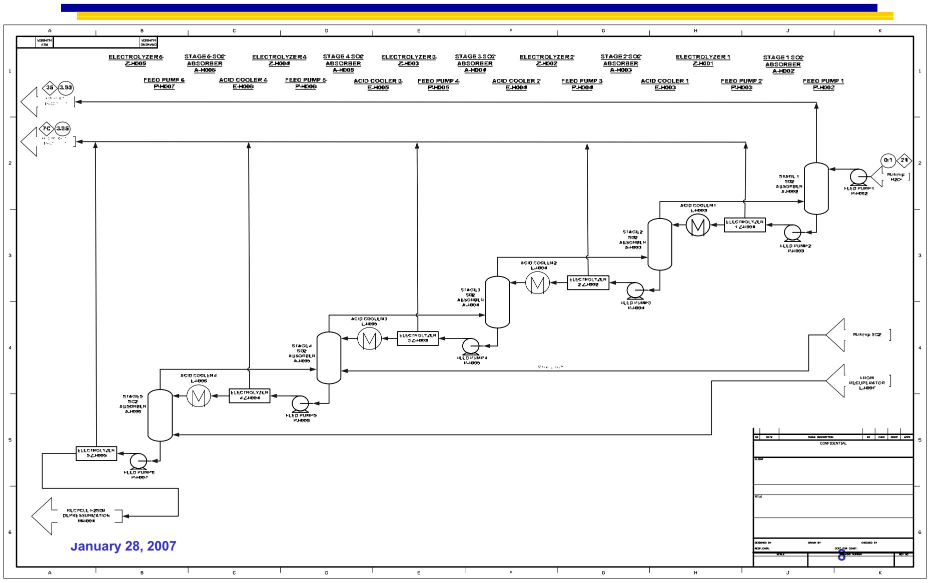
H2 Recuperator:	4.0 MWth
O2 Recuperator:	3.5 MWth
Sweep Heater and Steam Generator:	2.8 MWth
IHX or total PCHX Duty:	
With Recuperation	5.7 MWth
Without Recuperation	13.2 MWth
Electrolysis cells:	57 modules (each module has 40 stacks of 500 cells each) Modules are organized in units of eight modules

HyS Decomposition Flow Scheme



January 28, 2007

HyS Electrolysis Flow Scheme

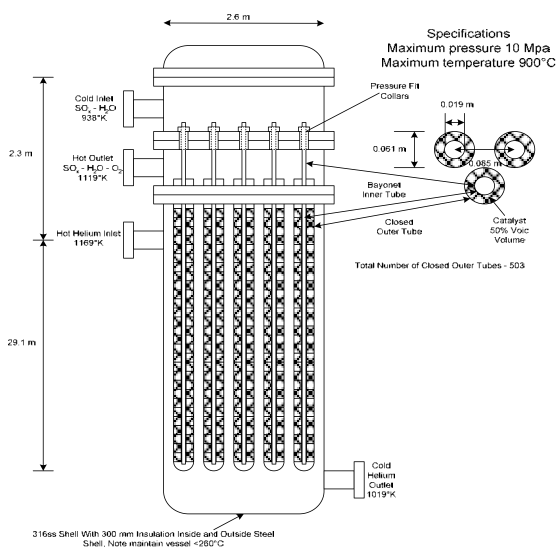


January 28, 2007

Smallest Required HyS Hydrogen Plant

- **Sulfuric Acid/ Sulfur Trioxide decomposer is clearly the critical piece of equipment**
  - Reference decomposer design (**Lahoda, E.J., et.al., <u>Estimated Costs for the Improved HyS Flowsheet,</u>** Proceedings HTR2006: 3rd International Topical Meeting on High Temperature Reactor Technology, October 1-4, 2006, Johannesburg, South Africa. Paper # C00000068
  - Remaining equipment in the flowsheet can be scaled from smaller tests and poses relatively minor challenges with respect to demonstration criteria
  - Full scale (200 MWth thermal input) plant requires about 30 electrolyzer units. Even a small demo of the decomposer will require commercial size electrolyzer units
    - *Only 200 MWth is used from the 500 MWth reactor because the conservatively designed decomposer returns helium at 660°C*
    - *Based on a converged simulation and*
    - *SI integrated design makes different assumptions*

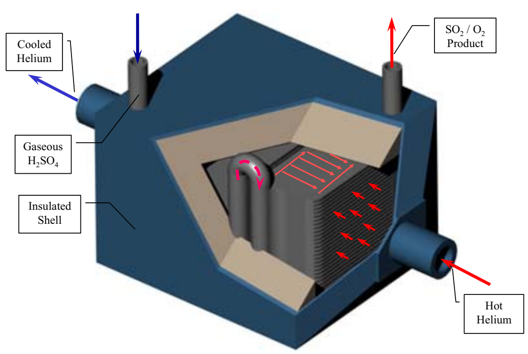
Reference Decomposer

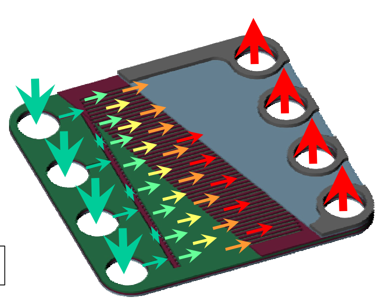


Smallest Required HyS Hydrogen Plant Sizing Process

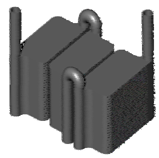
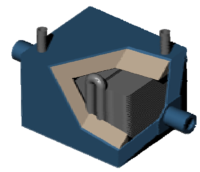
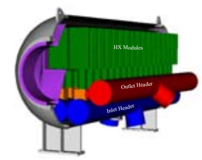
- **Reviewed the Westinghouse sizing calculations**
  - Added conservatism and re-sized the decomposer
    - ***2 ½ inch by 10 m tubes***
    - ***Additional surface area***
- **Used the latest material from Sandia NL to check the reactant residence time (personal communication with Fred Gelbard, Project Leader, Sandia Nat'l. Labs., 11/15/06)**
- **Calculated a duty per reactor tube**
  - 30 kW per reactor tube
- **From a tube bundle size of 150 tubes rounded duty up to the nearest MWth: 5 MWth**
  - Requires 167 tubes in the demo unit
  - Cell Area required is 410 m^2 for all five stages of electrolysis

Alternative HyS Decomposer: Ceramatec Shell and Plate Design





Ceramatec Development Path

2007

Sub-Scale Stack

- Fabrication Technology
- Heat Transfer Testing
- Performance

Multi-Stack

- System Issues
- Performance Data / Models
- Systems Integration
- **1 kWth**

Full-Scale Stack

- Engineering Prototype
- Process Scale-up
- Mfg Development
- Life / Reliability
- **250 kWth**

Process Demonstration

- System Operation
- System Demonstration
- Mfg Validation / Commissioning
- **5-10 MWth**

Smallest Required SI Hydrogen Plant

- **Either the sulfuric acid/ sulfur trioxide decomposer or the reactive distillation column will be the critical piece of equipment**
  - Work based on **Richards, M.B., et. al., H2-MHR Conceptual Design Report: SI-based Plant**, US DOE Contract No. DE-FG03-02SF22609/A000, GA-A25401, April 2006)
  - No detailed sizing information available for either of these units
  - A decomposer design is not proposed in the published reports
  - Equipment list of the report shows a single train for the H_2SO_4 and SO_3 decomposer whereas other sections have at least two and up to 10 parallel trains
    - *Assume that sulfuric acid decomposer is the critical piece of equipment*
  - This design returns helium at 558°C and delivers all the reactor heat to the decomposer

Smallest Required SI Hydrogen Plant (continued)

- **It may be possible to use the same decomposer for both processes**
  - Differences in the published energy balances for this part of the plant are due only to differences in assumptions and energy integration
  - Decomposition in both the HyS and SI processes accounts for the same portion of the energy required to split water.
  - The proportion between sulfuric acid decomposer size and hydrogen production rate will therefore be the same for both processes for a given decomposer design and integration with the IHX
  - Until additional conceptual design work is done on the sulfuric acid decomposer, the smallest required SI hydrogen plant is assumed to be based on the same capacity decomposer as for the smallest required HyS hydrogen plant

Smallest Required Hydrogen Plant Summary

- **High-Temperature Electrolysis can be demonstrated with a 1 MWth Superheater and with a total process-coupling heat exchanger duty of about 4.4 MWth**
- **Both Hybrid Sulfur and Sulfur Iodine may use the same size decomposer: 5 MWth**

Objectives

- **Size for demonstration of commercial feasibility**
  - Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- **Identify product and by-product markets**
- **Identify additional processing requirements**
- **Identify waste streams and disposal means**

HTE Commercial Train

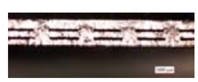
- **<10% of water-splitting energy is provided as thermal energy in the HTE process**
  - Helium is returned to the IHX at 292°C
  - With extensive recuperation
  - If the recuperation can be achieved, a full-scale PCHX duty would be about 50 MWth for a 500 MWth reactor

HyS and SI Commercial Train

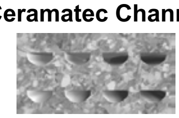
- **First full-scale HyS or SI plant will probably have multiple hydrogen production trains with decomposers rated at between 30 MWth and 100 MWth**
  - Based on the Reference HyS Decomposer design each 50 MWth decomposer (tubular design) will be about
    - *4½ meters in diameter*
    - *10 to 11 meters long*
    - *12.5 cm wall thickness*
    - *Have over 2500 ceramic bayonet tubes (each with catalyst in the annular space)*
  - Limits to size
    - *Fabrication limits, especially of the tubesheet*
    - *Sealing of ceramic to metal tubesheet*
    - *Aspect ratio for flow distribution of helium and heat transfer*
    - *Number of tubes for flow distribution of process fluids*
- **Micro-channel design will be physically smaller**
  - Both Ceramatec and Heatric see a current size limit of about 50 MWth

Commercial Scale

- **Heatric® Model**
  - Metallic Compact HX
    - *Diffusion Bonding*
  - Niche Markets
  - World-wide customer base
  - Max single unit ~ 50 MWth
  - Multiple units to scale
- **Ceramatec Model**
  - Ceramic HX core
    - *Micro/Mini Channels*
    - *Co-Sintering*
  - Partner
    - *HX Manufacturer*
      - Infrastructure
      - Vessel Fabrication
  - Size scaling:
    - *similar to Heatric*

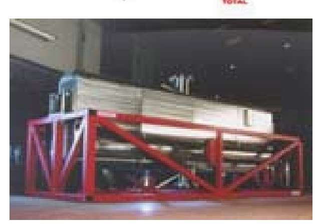


Ceramatec Channels



Heatric Channels

11 MW HX



42 MW HX

***Information obtained from www.heatric.com**

Smallest Required vs. Commercial Train Comparison

- **Smallest Required**
  - 5 MWth for HyS and SI
  - Comparable total PCHX duty for HTE
  - Adequate commercial demonstration of the hydrogen plant
  - Smaller cost and risk
- **Commercial Train**
  - About 50 MWth for HyS and SI (4 trains for full-plant)
  - 50 MWth for HTE full-plant with recuperation
  - Demonstration of effect of hydrogen plant operation on the nuclear reactor and heat transport systems
  - More convincing commercial demonstration, including operating costs
  - Facilitates expansion to full hydrogen production at NGNP

Objectives

- **Size for demonstration of commercial feasibility**
  - Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- **Identify product and by-product markets**
- **Identify additional processing requirements**
- **Identify waste streams and disposal means**

Hydrogen Production for Smallest Required Plant

- **High-Temperature Electrolysis case (4.4 MWth PCHX duty including recuperators)**
  - 0.224 kg/s = 8.0 million SCFD
- **Hybrid Sulfur case (5 MWth PCHX duty)**
  - 0.020 kg/s = 700,000 SCFD

  (derived from a Reference heat and material balance supplied by Westinghouse)
- **Sulfur Iodine case (5 MWth PCHX duty)**
  - 0.027kg/s = 970,000 SCFD

  (derived from GA-A25401)
  - Insufficient detail in the report to reconcile discrepancies
- **Commercial train production can be pro-rated based on power**

Objectives

- **Size for demonstration of commercial feasibility**
  - Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- ➡ **Identify product and by-product markets**
- **Identify additional processing requirements**
- **Identify waste streams and disposal means**

NGNP Product Markets

- **Electricity**
  - Based on a Wholesale Electricity Price Forecast by the Northwest Power and Conservation Council
- **Hydrogen**
  - Based on Air Products and Chemicals, Inc. (APCI) in-house marketing information
- **Oxygen**
  - Based on Air Products and Chemicals, Inc. (APCI) in-house marketing information

NGNP Electricity Market

- **Predicting the price of electricity from capacity coming on-line in 2018 is very difficult, the following should only be used for rough guidance**
- **Southern Idaho gets a substantial amount of electricity from the Pacific Northwest**
- **There is a large amount of hydroelectric capacity in this region**
- **In this region, electricity is cheap and getting cheaper**
- **Current forecasts for spot market prices in 2007 dollars and levelized between 2007 and 2025: $42/ MWth**

Uses For Hydrogen

- **Chemical and Pharmaceutical Industry**
  - The production of synthetic natural gas
  - The production of high-density polyethylene and polypropylenes
- **Electrical Industry**
  - Used as a fuel gas in the production and sealing of glass tubes
  - Used in hard-soldering for the manufacture of electronic equipment
- **Semiconductor Industry**
  - As a transport gas for diffusion processes
  - As a reactant gas with O_2 to generate water vapor for wet oxidation
- **Power Stations**
  - For cooling generators, motors, and frequency converters

Uses For Hydrogen

- **Hydrogenation of Oils and Greases**
  - Delays the tendency of oil to oxidize and turn rancid
- **Metal Processing – Ferrous Metals**
  - Increased ductility
  - Higher yield point
- **Metal Processing – Non Ferrous Metals**
  - Annealing of copper and copper alloys
  - Used in the production of magnesium by electrolysis
- **Welding and Cutting**
  - Plasma cutting and welding
  - Soldering and welding in a protective atmosphere

Uses For Hydrogen

- **Glass / Quartz**
  - Used as a fuel gas in combination with oxygen for the cutting and melting of quartz
- **Petroleum Industry**
  - Desulphurize and hydrocrack crude oil fractions
- **Transportation fuel**
  - Internal combustion engines or turbines
  - Fuel cells

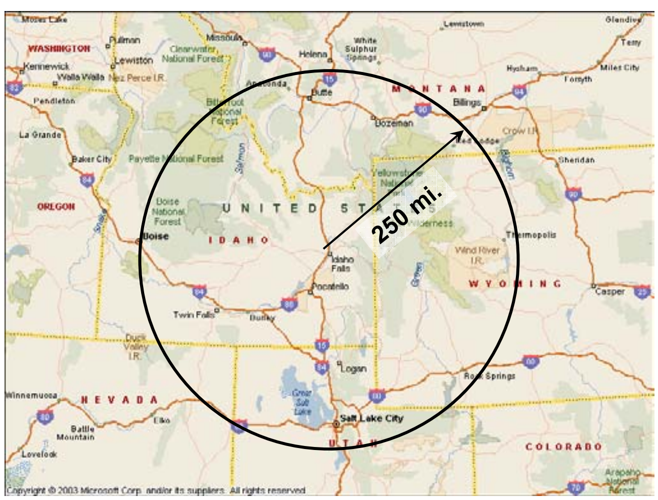
U.S. Chemical Products Using Hydrogen in Their Manufacture

Adiponitrile	Alkylamines	Aniline	1.4-Butanediol
Butene-1	Butyrolactam	Butyrolactone	Calcium hydride
Caprolactam	Fatty Acids	Cyclohexane	Cyclohexanol
Cyclohexanone	Hydrochloric acid	Dodecanedioic acid	Phosgene
Ethyleneamines	Dodecanediamine	Hexamethylenediamine	Furyfuryl alcohol
Hydrochloric acid	Hydrogen peroxide	Hydrogenated bisphenol A	Hydrogenated rosin
Poly (alpha-olefins)	Polybutene-1	Sodium hydride	Sorbitol or ascorbic acid
Terephthalic acid	Tetrahydrofuran	Tetrahydrofurfuryl alcohol	Toluenediamine
Furyfuryl alcohol	Polyethylene	Polypropylene	Polypropylene oxide
Hydrogenated styrene	Hydrogen bromide	Pharmaceuticals	Hydrogenated terpene derivatives
Lithium hydride	Piperidine		

Hydrogen Distribution Options

- **Pipeline (necessary for full plant -- 4 trains)**
  - 0.5 to over 100 million SCFD
  - Depends on pipeline availability
- **Liquid Hydrogen (choice for commercial train)**
  - Up to about 1 million SCFD
  - Requires extra purification and liquefaction
- **Tube trailer (choice for smallest required hydrogen plant)**
  - Up to about 400,000 SCFD
- **Cylinders**
  - Up to about 100,000 SCFD

Economic Shipping Radius for Compressed Hydrogen



Potential NGNP Hydrogen Markets

- **Six companies identified within shipping distance that use bulk compressed hydrogen**
  - All are metals processing applications
  - Combined annual consumption is < 200,000 SCF per *YEAR* (NGNP will produce at least 500,000 SCF per *DAY*)
- **There are three refineries within shipping distance**
  - All supply needs by on-site generation or pipeline purchase
  - There may be a future opportunity
- **No float glass producers**
- **No chemicals producers that use hydrogen**
- **Possible local transportation fuel**

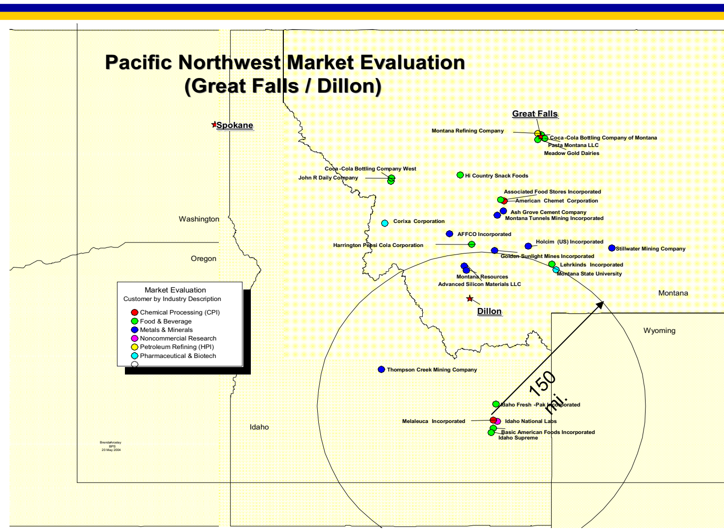
Hydrogen as transportation fuel

- **Need to develop a local fleet of cars or buses**
- **1 kg of hydrogen has a heat of combustion equivalent to a gallon of gasoline and roughly 10% less than a gallon of diesel**
- **U.S. Climate Change Technology Program target for urban buses: 10 mpg (gasoline equivalent)**
- **Assume 15 miles per hour (average) running 16 hours per day per bus**
- **The 5 MW NGNP small demo plant will support a fleet of approximately 70 buses**

Liquid Hydrogen

- **Shipping radius will be increased to 1000 miles, greatly increasing market possibilities**
- **If hydrogen is to be liquefied for transportation and distribution purposes, it must be purified to a very high degree (H_2 b.p. = 20.4 K)**
- **High purity hydrogen is a different product for different markets**
- **Additional cost of production is large ($1.50/kg)** (Ref WSRC-TR-2004-00318, Rev.0 ("Phase A report"), Appendix A)
  - Cost of additional purification
  - Cost of liquefaction
  - 5 MWth Plant will produce about 2 tons per day of hydrogen

Potential Market for NGNP Plant Oxygen



Oxygen Users within 150 Miles of NGNP

Chemical Processing (CPI)

- Melaleuca Incorporated

Metals and Minerals

- Montana Resources
- Advanced Silicon Materials LLC
- Thompson Creek Mining Company

Noncommercial Research

- Idaho National Labs

Oxygen users in the INL Region

- **Major uses**
  - Oxy-fuel cutting
  - Combustion enrichment for glass and ore smelting
  - Breathing
- **Oxygen is inexpensively extracted from air on-site by most larger users**
  - Low-purity applications served by pressure-swing adsorption (PSA) units
  - Mining and smelting usually served by on-site PSA or cryogenic separation
  - High-purity breathing oxygen supplied from centralized cryogenic units
- **INL on-site use may be the best market for oxygen**

Objectives

- **Size for demonstration of commercial feasibility**
  - Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- **Identify product and by-product markets**
- **Identify additional processing requirements**
  - Identify purity requirements
- **Identify waste streams and disposal means**

Hydrogen Purity Requirements

	End Use Application		
	Surface Vehicle Fuel Cell	Glass, Chemicals	Refining
H2 Purity (Mol%)	> 99.99%	99.995%	99.90%
Contaminant (ppmv)			
Total Non-H2 or particulate	100	50	1000
Total Hydrocarbons	2	1	n/a
Oxygen	5	1	1
Inerts (He, N2, Ar)	60	2	< 1000
Carbon Dioxide (+ Carbon Monoxide)	1	1	10
Total Sulfur	0.004	5	5
Formaldehyde	0.01	n/a	n/a
Formic Acid	0.2	n/a	n/a
Ammonia	0.1	n/a	1
Total Halogenates (I, Br, Cl, F,)	0.05	n/a	1
Water	5	1.5	10
Particulate	< 10^{-3}mm @ 10^{-6}g/l	n/a	n/a

Oxygen Purity Requirements

	End Use Application		
	Oxy-Fuel Cutting	Combustion Enhancement	Breathing Oxygen
O2 Purity (Mol%)	> 99.5%	99	99%
Contaminant (ppmv)			
Total Hydrocarbons	n/a	< 0.5	< 50
Inerts (N2, Ar)	< 0.4%	< 1%	< 1%
Carbon Dioxide	n/a	n/a	< 300
Carbon Monoxide	n/a	n/a	< 10
Total Sulfur	n/a	n/a	No Odor
Total Halogenates (I, Br, Cl, F,)	n/a	n/a	n/a
Solvents	n/a	n/a	< .1
Others by Infrared	n/a	n/a	< .1
Water	< 50	< 50	< 6.6 (liquid)

Purification Processing

- **High-Temperature Electrolysis Product**
  - Modest requirements
    - *Drying*
    - *Regenerable desiccants (in situ)*
- **Hybrid Sulfur and Sulfur Iodine have similar requirements**
  - Complete removal of sulfur species
  - Complete removal of halogens
  - Drying
  - Caustic scrubbing followed by a non-regenerable adsorbent

Tritium Production and Removal

- **Sources of Tritium (H^3) in the Helium Coolant**
  - Activation product from small percentage of helium atoms that are He^3 (dominant contributor)
  - Activation products from impurities and control material such as Li-6 and B-10 may remain in the graphite or migrate into the coolant,
  - Ternary Fission (remains almost entirely in the fuel particles)
- **Removal Paths from the Helium Coolant**
  - Helium Purification System (HPS) removes most of the tritium in the form of tritiated water that can be stored or discharged to the environment at concentrations below the allowable limits
  - Leakages to the atmosphere and permeation to the secondary coolant and process fluids can be limited by appropriate design of penetrations, seals and HPS

Estimated Tritium Production for the NGNP

- **Based on extrapolation from THTR operating data**
  - ~91Ci annual liquid discharge; limit was 1000Ci/a
  - H^3 level in the coolant remained constant which implies that production equaled discharge
- **Tritium production from activation of He^3 is proportional to**
  - the reactor power (higher thermal flux in the core produces more tritium)
  - the primary coolant density (higher density makes more He^3 atoms available for activation)
- **Estimated NGNP(@500MWt, 9MPa) tritium production from He^3 is ~115 Ci/a**

Objectives

- **Size for demonstration of commercial feasibility**
  - Smallest hydrogen plant required
  - Commercial train
- **Identify production rate for each demonstration case**
- **Identify product and by-product markets**
- **Identify additional processing requirements**
  - Identify purity requirements
- **Identify waste streams and disposal means**

Waste Streams

- **Feed water purification**
  - Ion exchange bed regeneration waste
    - ***Acidic***
    - ***Basic***
  - Spent ion exchange resin
  - Not quantifiable without feedwater and supply specifications
- **Process blowdowns**
  - HTE – at least one: removal of dissolved solids
  - Hybrid Sulfur – one stream of sulfuric acid
  - Sulfur Iodine – at least two, one of which will contain iodine and iodic acid
  - Not quantifiable without data on tolerance of process to impurities

Waste Streams (continued)

- **Purification wastes (quantities for smallest required hydrogen plant)**
  - Spent caustic (about 715 tons/year of sodium sulfate in a dilute water solution)
  - Spent adsorbent (about 116 tons/ year for Hybrid Sulfur)
- **Boiler and cooling water blowdowns**
- **Radioactive wastes**
  - Fuel elements
  - Reflectors
  - Control rods
  - In-core flux mapping units
  - tritiated water

Comparison of Demonstration Sizes

- **Smallest Required**
- **5 MWth**
  - Difficult to find product destinations even at this size in current market
  - Will support a small fleet of buses
  - Large, but manageable waste streams can be treated or disposed of off-site

- **Commercial Train**
- **about 50 MWth**
  - Requires emergence of a local hydrogen economy, otherwise there may be market disruptions
  - Waste quantities will require consideration of on-site processing

Conclusions

- Production from either Hybrid Sulfur or Sulfur Iodine small scale demonstration would support a fleet of local buses
- High-Temperature Electrolysis would probably require product liquefaction to find users even at small scale
- Research needed on the effect of likely impurities on each of the systems and likely operating concentrations
- Waste disposal does not impose limits on the small demo size
- Demonstrating a full-scale plant module should be considered further