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ATTACHMENT 1

MID-COLUMBIA CLEAN ENERGY FEASIBILITY ASSESSMENT
DOE/RL-2011-117

Consisting of 136 pages,
including this cover page

Mid-Columbia Clean Energy Feasibility Assessment

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Revision 0

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Mid-Columbia Clean Energy Feasibility Assessment

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EXECUTIVE SUMMARY

The Mid-Columbia region in southeastern Washington State has the potential to become a national leader in renewable energy production. At the same time, the region's existing infrastructure can demonstrate industry best practices in sustainability. The regional energy sector has long enjoyed abundant resources, and continues to do so today with kilowatt-hour prices among the lowest in the nation. Several interrelated drivers propel the analysis of commercial development feasibility for clean energy resources: the U.S. Department of Energy (DOE) Asset Revitalization Initiative intended to help economic development in regions near DOE sites; an increase of approximately 100 megawatts in near-term demand for electricity in the Pacific Northwest; growing market demand for low-carbon footprint fuels; and the Mid-Columbia Energy Initiative. There is a growing sense that is found among local government and private sectors that the Mid-Columbia community should marshal its forces and contribute to developing a framework for local clean energy power and fuels production, which takes advantage of locally available resources to help drive forward developing a clean energy industry in the region and the nation.

This assessment focuses on relevant forms of clean energy available in the region, local needs and resources, and other pertinent economic and business related considerations. An overall analysis of clean energy sources is included that compares solar, biomass/biofuels, wind, geothermal, and municipal waste reuse processes and integration of clean energy resources with other power sources such as natural gas where available. The study provides a system-engineered body of knowledge to help future decision making about potential development of commercially viable low-greenhouse-gas-producing energy generation capabilities that will meet the needs of federal agencies such as the DOE, U.S. Department of Defense (DOD), and the Bonneville Power Administration, as well as local communities.

This study includes results from previous studies as a basis and considers related aspects of supply chain engineering. The results are as follows:

- Economic and technical analysis of available clean energy supply chains
- An effective approach that addresses alternatives to biological or waste resources, preferred crops, transport and processing, integration of renewable resources with other potential energy sources such as natural gas, and potentially profitable commercial development business cases
- The potential for coordinating wind resources with existing operations to more efficiently integrate wind power onto the existing grid system.

The primary purpose of this document is to perform an engineering evaluation of relevant forms of clean energy available in the Mid-Columbia region. This report is intended to be used as a feasibility study to evaluate the practicality of potential commercial clean energy technologies, as well as a marketing tool for economic development. Although a top-level cost analysis of several clean energy value propositions is discussed, study results are based on current energy prices from the U.S. Energy Information Agency (http:/www.eia.gov) as of October 2011. Wholesale forecasted benchmark energy prices were not used since investments in future projects are heavily dependent on the expected timeline of proposed projects. Therefore, it is expected that investors and other business entities would perform their own requisite due diligence with respect to further cost analysis investment endeavors, projected on timelines specific to their proposals.

It must be stressed at the outset that the underlying premise of this analysis is that clean energy technologies are only practical when they reach cost parity with conventional offerings. The findings of this analysis are such that certain select clean energy technologies appear to be cost competitive in the Mid-Columbia region with reasonable returns on investment, in particular with the planned and well-executed integration of local clean energy resources with conventional energy sources.

The goal of this feasibility assessment is to provide near- and long-term planning, taking into account the uncertainties of economic and technical challenges and the opportunities for significant clean energy deployment are illuminated and balanced. The report highlights these opportunities and risks.

FINDINGS

This study has shown the presence of available resources in the Mid-Columbia region to meet clean energy needs and requirements of federal agencies, and to support future development of a viable commercial clean energy industrial base. This report also highlights several business development conditions that would help support creation of that industrial base. Finally, it has revealed several separate but mutually supporting “value propositions” (further defined below) to be considered by civic authorities, potential developers, and investors. These value propositions are not recommended courses of action; rather, the value propositions present a set of “existence proofs” to show possible paths forward for decision making, planning, and to support due diligence processes required for future development. Figure ES-1 presents the technical scope of clean energy pathways evaluated in this feasibility study.

RESOURCES

Biomass: A review of biomass resources in the Mid-Columbia region shows a strong base of agricultural waste biomass available for exploitation. There is sufficient biomass to support a demonstration-scale power plant or a biomass-to-liquid fuels plant of 75 megawatts or 22 million gallons, respectively. With further development of regional transportation around centralized facilities, there is sufficient biomass in the region to support large-scale production. This resource, principally in the form of wheat straw, can be obtained as a waste byproduct of food production. Biomass-based energy production would have no impact on food supply or land use and little on water resources, and could have a positive effect on the agricultural economy of the region. Other biomass resources include waste from alfalfa seed production, corn harvesting, and winery wastes; however, the large amounts of wheat straw available in the region are the focus of the feasibility study. Two other sources, woody biomass and municipal solid waste, were considered and show much promise; however, most of those resources are generated on the western side of the state and thus would be somewhat costly for transporting it to the local region for processing. Technologies needed to produce power or fuel from waste biomass exist and appear to provide a path for development that will work functionally and economically.

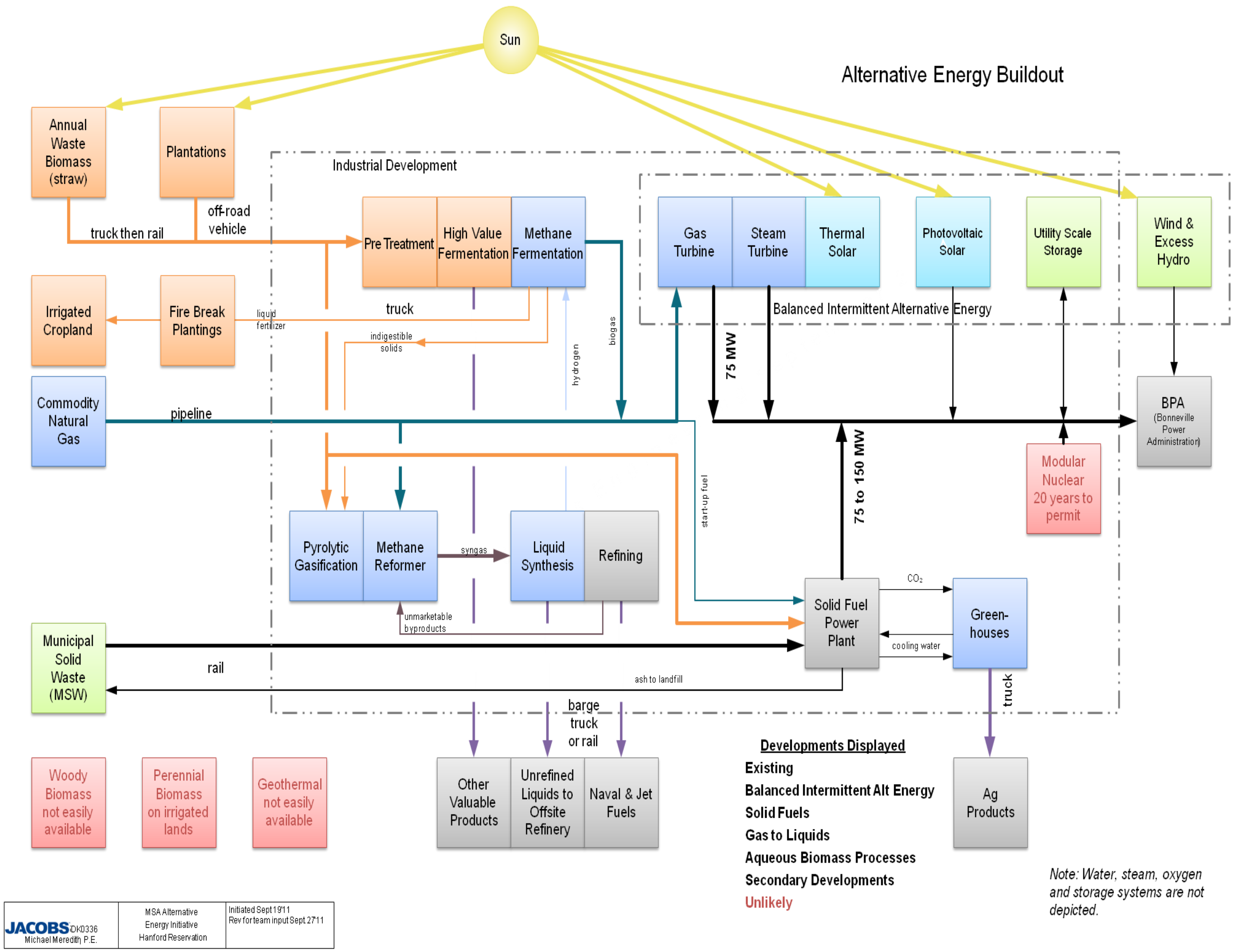

Figure ES-1. Technical Scope of Clean Energy Pathways.

Solar and Geothermal: These clean energy sources show promise for meeting the region's clean energy needs; however, both sources have issues that may make them less attractive than biomass. Solar is adversely affected by a less-than-ideal regional solar index (notably during winter months), even with the low current cost of photovoltaic cells.

Geothermal heat is a very promising resource in broad areas of the Pacific Northwest, but high-temperature rock in the local region is only found at very great depths, so the economics of geothermal power are not outstanding. Other uses for geothermal energy, principally from shallow resources, could be very useful for improving efficiency of heating and air-conditioning systems.

Natural Gas: Although natural gas is technically a fossil fuel, it has low carbon content and its low cost makes it an important energy source in the Mid-Columbia region. The potential for using available natural gas as an "enabler" to encourage additional clean energy development is a critical concept. Natural gas could be used for bio-sourced gas infrastructure development in electricity generation or liquid fuels production. For example, a natural gas powered electricity peaking plant could be a practical investment for a commercial developer, making power to balance wind generation for integration onto the grid, meeting short-term needs of grid managers, and supplying power for extended periods during low river-flow and wind conditions. If specified correctly, and with appropriate off-taker agreements in place, that same power plant could operate on gas produced from biomass with appropriate infrastructure in place. Similarly, a natural gas-to-liquid plant using existing technology could be an off-taker for gas from a biomass processing plant as well.

Water Use and Water Rights: Essentially all industrial processes, including electricity generation, fuel production, and biomass processing use significant amounts of water. Water rights are a major issue in North America, and southeastern Washington State is no exception. The Federal Government has reserved water rights for defense purposes in the area; however, those rights may not be available for clean energy development. For environmental and capacity reasons, groundwater (i.e., water pumped from wells) is not likely to provide a significant resource. Use of water from the Columbia River is tightly controlled; however, the communities in the Mid-Columbia region have secured long-term rights for local economic development. Water resources for development have to be identified early and local authorities should be prepared to render assistance to developers to facilitate development of business arrangements leading to major investment. Pre-existing arrangements to meet green energy development water needs would be a significant asset for the community in a search for potential developers.

Community Support: The Tri-Cities area (Richland, Pasco and Kennewick) is centrally located in the Mid-Columbia region and has a long history of being at the forefront of energy development and technology. The area has a diverse power portfolio that includes hydro, wind, solar, nuclear, and coal energies. Forty percent of Washington State's power is produced within a 100-mile radius of the Tri-Cities, including hydroelectric, nuclear (from the Columbia Generating Station), and wind power.

The region has an established community of industry and a strong government presence with a history of working together for common goals. The record of cooperation between the Tri-Cities is embodied by the Tri-City Development Council (TRIDEC), which was created to coordinate and assist economic development of the local area. TRIDEC established the Mid-Columbia Energy Initiative (MCEI) capitalizing on local resources and expertise in energy to enable development of a significant energy industry for the region and to recruit and retain energy-centered businesses in the area. A cornerstone to this community vision is the establishment of the Tri-Cities Research District, which is intended to build an atmosphere and physical infrastructure to attract innovative research organizations. The Bioproducts, Sciences, and Engineering Laboratory at Washington State University (WSU) Tri-Cities Campus is located within the Tri-Cities Research District. The Bioproducts, Sciences and Engineering Laboratory established itself as a world-class center for biomass processing and bio-engineering for energy and other potential areas of application.

With its strong history of collaboration among institutions and robust technical capabilities, this region is poised to play an extensive and supportive role in providing clean energy production.

VALUE PROPOSITIONS

Several clean energy business cases were evaluated to provide reasonable assurance that conditions in the local region will support clean energy project development. Several of these concepts have potential to serve as value propositions to demonstrate possible paths forward, they are as follows:

> **Value Propositions**
>
> - The Mid-Columbia region has access to significant quantities of renewable energy sources (straw and municipal solid waste) that may be profitably converted into liquid fuels, high value chemicals, electricity and other products, with natural gas providing a potential backup source.
> - This profit potential is achieved by multiple process plant types that are interrelated and together produce process synergies and operating flexibility.
> - The opportunity to produce clean energy and green end-products is facilitated by strong regional economic development support.

Exploitation of Natural Gas to Enable Creation of Clean Energy: Natural gas is efficient, relatively clean and economical, and available from domestic sources. It also may provide future opportunities that result in a supportive business development environment for clean energy. Local stakeholders can encourage development of natural gas-based projects that, while independent of technology and process development of renewable energy sources, can act as assured off-takers for those sources when they are ready for commercial production.

Power: The Northwest Power and Conservation Council states the *Sixth Northwest Conservation and Electric Power Plan* identified a need for additional power generation capacity for the region to help efficiently integrate wind power onto the grid, and to add sustained capacity to the system in high demand periods. This demand tends to push solutions toward simple turbine installations that do not use combined-cycle thermal adjuncts due to their ease of operation and low capital cost. A natural gas-fueled peaking plant that uses efficient and responsive gas turbine or internal combustion power could use biomass-sourced gas produced in new facilities in the Mid-Columbia region and regional biomass from agricultural waste.
A natural gas-fueled peaking plant would be a practical business proposition with or without bio-derived gas, and would have lower risk for an investor than a plant that was a specialized design for biogas only. At the same time, it would provide an assured off-taker for a biomass gas plant, improving the potential for developing a biomass industry in the area. A natural gas-fueled electric generating plant with a defined path to bio-derived gas use would be a good candidate for industrial development.

Fuel: Due to the high cost of fuels and the relatively low cost of electricity in the Pacific Northwest, liquid fuel production may be more economical than electrical generation. Such technology is relatively mature, with some commercial-scale plants currently in production. A natural gas-to-liquid plant, with a long-term option to use bio-sourced gas to supplement or replace natural gas when economic conditions warrant, is a business case worth pursuing for the region.

Biomass: An evaluation of biomass resources in the Mid-Columbia has identified that wheat straw is a potentially rich biomass resource produced as waste from wheat growing. Other significant sources, such as alfalfa straw and wine industry waste, exist in smaller amounts. New technologies for processing agricultural waste into gas for direct use or further processing into liquid fuels are developing rapidly, with the potential for reasonable economic return. These new technologies need to be brought into industrial service showing solid returns and low risk of development as they are industrialized and grow in capacity. The existence of local off-takers, including a gas generating plant and/or a gas-to-liquid plant, would serve as an important incentive for investors and developers.

Additional High-Value Products: Biomass-derived gas can be processed into other important and profitable products such as fertilizers, industrial solvents, adhesives, and plastics. Financial return on these products is often much higher than for energy, and these non-energy industries may become attractive development candidates. While much attention is focused on energy development, this industrial chemical path should not be discounted in master planning.

These concepts and their interrelation are laid out in Figure ES-2. The combination of these separate paths, economically independent but mutually supportive, provides a smart path for local stakeholders to build a clean industrial base for the region.

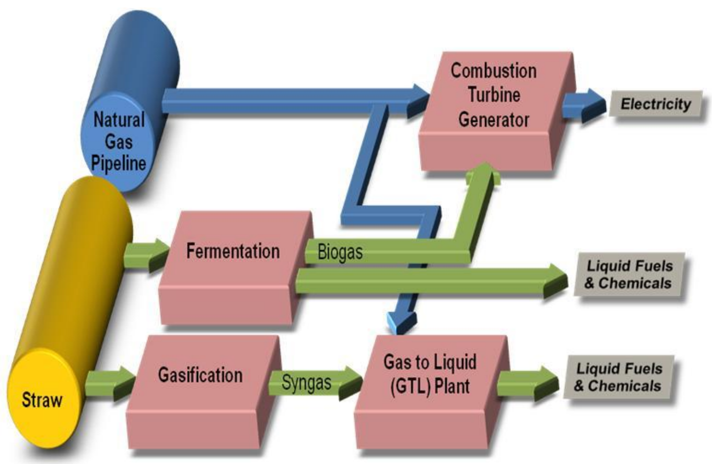

Figure ES-2. Economically Viable and Separate Paths to Produce Clean Energy and Valuable Products.

CONCLUSIONS

This report focuses on the viability of clean energy technology development for the Mid-Columbia region. While considerable research and analysis was conducted on examining technology viability, there is equal emphasis on the nature of sequencing or phasing the path forward of a gas-to-liquid plant, natural gas plant, and biomass power plant, which is economically important for commercial startup. Figure ES-3 portrays the importance of sequencing of a biofuels facility through pilot-scale to commercial-scale in combination with a natural gas power plant or a gas-to-liquid plant.

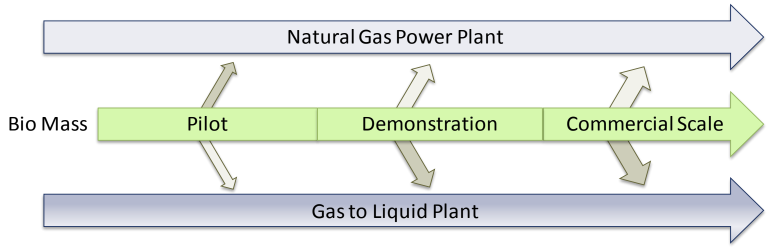

Figure ES-3. Scale-up of Biomass Plant in Combination with Natural Gas.

Federal, state and local officials, community reuse and economic development leaders, regulatory authorities, and industry executives need to recognize the importance of maintaining momentum through such a phased approach if the region is to realize the benefits of local clean energy production.

The feasibility study shows that business economics in the region are driven by the abundance and transportation cost of biomass and that wheat straw is the predominant source for biomass in the Mid-Columbia region. Trucking is the current method in Central Washington for transporting baled straw and other biomass. Developing biomass processing capacity will require additional development of logistics and infrastructure. As the size of operating plants increase, transportation via rail and/or barge from increasing distances may become more cost effective.

Development of economically viable clean energy industries is most likely to succeed if developed in coordination with conventional energy sources, and integrating with existing infrastructures wherever possible. Federal, state, and local government agencies, as well as regional civic organizations, working toward a common strategic goal to create those conditions necessary to enable industry development, stand a better chance of succeeding in fostering development than if such efforts are undertaken separately. This report discusses resources and attributes available in this area to support development. The Mid-Columbia region possesses the needed attributes to support success and the combination of readily available resources, existing infrastructure, a supportive civic environment, potential markets, and the room to grow in the region makes the local area an exemplary test case for clean industry development as a part of the greater United States economy, and potentially the world.

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– Grant County Public Utilities District
– Northwest Power and Conservation Council
– Tidewater Barge

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FIGURES

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ABBREVIATIONS AND ACRONYMS

AD	anaerobic digestion
B&W	Babcock & Wilcox
BCC	BioChemCat
BIPV	building integrated photovoltaic
BPA	Bonneville Power Administration
Btu	British thermal unit
CAES	compressed air energy storage
CHP	Combined Heat and Power
CSP	concentrated solar power
CST	concentrated solar thermal
DNI	direct normal insolation
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
EGS	enhanced (or engineered) geothermal systems
EIA	U.S. Energy Information Administration
FeCr	Iron Chromium
FEMP	Federal Energy Management Program
FY	Fiscal Year
GE	General Electric
GHG	greenhouse gas
GHP	ground source heat pump
gpm	gallons per minute
GTL	gas-to-liquid
HAWT	Horizontal Axis Wind Turbines
HRSG	heat recovery steam generator
HVAC	heating, ventilation, and air conditioning
IC	internal combustion
ITC	Investment Tax Credit
kW	kilowatt
kWh	kilowatt hour
LCOE	Levelized Cost of Energy
MAIL	metal air ionic liquid
MCEI	Mid-Columbia Energy Initiative

Mgal	million gallons
MIT	Massachusetts Institute of Technology
MSA	Mission Support Alliance, LLC
MSW	municipal solid waste
MW	megawatt
MWh	megawatt hour
NaS	Sodium Sulfur
NASS	National Agricultural Statistics Service
NO_x	nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NWHA	Northwest Hydrogen Alliance, Inc.
NZEI	Net Zero Energy Initiative
OD	Oven Dry
O&M	operations and maintenance
PEM	polymer electrolyte membrane
PHES	pumped hydro energy storage
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PSB	PolySulfide Bromide
PV	photovoltaic
R&D	research and development
REC	renewable energy credits
SOC	state of charge
TES	thermal energy storage
TRIDEC	Tri-City Development Council
UGA	urban growth area
VRB	Vanadium Redox
WSU	Washington State University
WTE	Waste-to-Energy
ZnBr	Zinc Bromide
ZnCl	Zinc Chloride

1.0 BACKGROUND

This feasibility assessment focuses on clean energy that is available in the Mid-Columbia region, local needs and resources, and other pertinent economic and business related considerations. An overall analysis of clean power sources is described that compares solar, biomass/biofuels, wind, geothermal, and municipal solid waste (MSW) reuse processes. This assessment also considers integrating clean energy resources with other potential power sources such as natural gas and hydroelectricity.

This assessment provides a system-engineered body of knowledge to help inform decision makers on development of commercially viable, low-greenhouse-gas (GHG) producing energy generation capabilities to meet the future needs of the local region including federal agencies such as the DOE, U.S. Department of Defense (DOD), and Bonneville Power Administration (BPA), as well as commercial markets. The study also uses results from previous studies as a basis, and considers all aspects of supply chain engineering. Study results include:

- Economic and technical analysis of available clean energy supply chains
- An optimized approach that addresses alternatives to biological or waste resources, preferred crops, transport and processing, integration of renewable resources with other potential energy sources such as natural gas, and viable commercial development business cases
- The potential for coordinating operations with wind resources to more efficiently integrate wind power onto the existing grid system.

1.1 METHODOLOGY

This study was conducted by the Mission Support Alliance, LLC (MSA) with support from subject matter experts from Lockheed Martin, Jacobs Engineering, Washington State University (WSU) – Tri-Cities, and Fox-Potomac Resources. The content of the report and its conclusions are based on economic and technical analysis from these subject matter experts. Due to the time constraints of the report, top-down analysis and estimating was used for some areas of scope, schedule and costs. Given the abbreviated study period and future energy costs, the top-down approach encompasses a degree of uncertainty; however, development of the technological feasibility assessments and costs were based on the aggregation of logical, discrete units of work, mitigating this uncertainty to a large degree.

An Integrated Project Team was formed to assess the discrete technologies of solar, wind, geothermal, small modular reactors, natural gas, biomass, conservation/efficiency, and grid-scale storage. Lockheed Martin addressed project integration, energy storage, utility-scale clean energy, wind, and solar technologies. MSA and Jacobs Engineering team members assessed the viability of small modular reactors and technologies for conservation/energy efficiency. Jacobs Engineering evaluated energy plant engineering; co-generation; engineering, procurement and construction; and biomass technologies. WSU supported the biomass analysis content of the report.

The feasibility assessment was driven by technical data collection and analysis; interviews and discussions with state, county, and federal resources; and surveys of technologies and markets. Significant input was derived from local community, civic, and economic development organizations regarding site and regional attributes and assets; however, the content of this report remains the responsibility of the authors.

1.2 NEEDED POWER ATTRIBUTES

The Northwest Power and Conservation Council states in the *Sixth Northwest Conservation and Electric Power Plan* that between 2009 and 2030, the load is expected to increase by an average of 335 average megawatts (MW), or 1.4 percent/year for the Pacific Northwest. BPA noted that the Mid-Columbia region will need an additional 150 MW of power by the year 2020. This increase is one of the critical drivers for this feasibility study.

1.2.1 Dispatchability and Integration

Power plants with low variable-production costs operate primarily to produce electrical energy as base load power. Little can be saved by limiting their operation, so they are dispatched to the grid to the extent that they are available for operation. Because non-fuel variable costs are a minor element of production costs, base load units tend to be those with low (or no) fuel costs such as coal, hydropower, geothermal, biogas, wind, solar, and nuclear plants. Natural gas combined-cycle plants are very efficient, so they typically operate as intermediate load units producing energy at times of higher demand and prices, but are curtailed during periods of low-energy prices. Cogeneration plants, though often using expensive fuel (natural gas or residue biomass), are efficient and normally have a steady thermal load, so they can operate as base load plants.

A challenge to increasing variable-output clean energy resources like wind, solar, wave, and tidal current generation is shaping the variable of these resources to meet the power quality standards and load of the power system. Power available on demand, referred to as dispatchable power, is needed for this function. One approach is to use dispatchable firm generation like hydropower, which is currently used to integrate wind power in the Pacific Northwest. An alternative is energy storage technology. Energy storage technologies decouple the production and consumption of electricity and can provide regulation, sub-hourly load-following, hour-to-hour storage and shaping, firm capacity, and other ancillary services. Storage projects within a renewable resource zone can be used to flatten the output of variable-output generation, thereby increasing transmission load factors and improving the economics of long-distance transmission.

Reliable operation of a power system requires minute-to-minute matching of electricity generation to varying electricity demands. In the Pacific Northwest, resource planners focus mostly on annual average energy requirements, leaving the minute-to-minute balancing problem to system operators. Historically, this was because the hydroelectric system had sufficient peaking capacity and flexibility to provide the needed operations as long as there was sufficient energy capability. This is changing for several reasons: Growing regional electricity needs are reducing the share of hydroelectricity in total demand, peak load has grown faster than annual energy, the capacity and flexibility of the hydro system has been reduced over time for fisheries conservation, and growing amounts of variable wind generation have added to balancing requirements of the system.

As a result, planners must consider potential resources in terms of their energy, capacity, and flexibility contributions. The rapid growth of wind generation (which has little capacity value and increases the need for flexibility reserves) means that meeting growing peak load and flexibility reserves will require adding these capabilities to the power system. Changes can be made to the operation of the power and transmission system that will reduce flexibility reserve needs. These operational changes are expected to cost less than adding peaking generation, demand response, or flexibility storage and they can be implemented more quickly.

Continued development of wind power to meet regional clean energy portfolio standards, as well as for export, will continue to increase the demand for flexibility reserves. Flexibility reserves (also called balancing reserves, rapid-response reserves, or regulation and load-following capability) provide the ability to balance generation and load on a sub-hourly basis; balancing within intervals of seconds to minutes is referred to as regulation, and balancing within the hour is referred to as load following.

As identified by the Northwest Power and Conservation Council in the *Sixth Northwest Conservation and Electric Power Plan*, there is a growing need for flexibility of the existing grid system. Their recommendations include modifying existing operating procedures and business practices to allow the maximum and most efficient use of the region's existing flexibility for those balancing authorities with large amounts of wind generation. Secondly, the new dispatchable generation capacity required to meet the peak-hour capacity needs of the system should be capable of adjusting up or down to deal with changes in wind output and allow the region's balancing authorities to maintain their area control error[1] measures within acceptable bounds.

The Northwest Power and Conservation Council address the need for wind and grid integration in the *Sixth Northwest Conservation and Electric Power Plan*. The primary need includes integrating wind power in the spring months during conditions of high-water spillage through the hydroelectric system coupled with high-spring winds resulting in excess generation capability. Past spring conditions required the BPA wind generators to turn off generation of power.
The Northwest Power and Conservation Council notes that wind integration and within-hour reserves need to be addressed through improvements in the operating system and procedures, changes in wind forecasting, reserve sharing among control areas, scheduling the system on a shorter time scale, and advancing dynamic scheduling to contribute to more efficient use of existing system flexibility.

[1]Area control error - A measure of the instantaneous difference in scheduled and actual system frequency and a balancing authority's scheduled and actual interchanges with other balancing areas.

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2.0 REGIONAL ASSETS AND ATTRIBUTES

2.1 SUPPORTIVE HOST COMMUNITY AND RESOURCES

The Tri-Cities area has a long history of being at the forefront of energy development and technology. The area has a diverse power portfolio that includes hydro, wind, solar, nuclear, and coal energies. Forty percent of Washington State's power is produced within a 100-mile radius of the Tri-Cities. Nuclear fuel locally manufactured by AREVA Inc. Richland, supplies 5 percent of the electricity consumed in the Unities States.

The Tri-Cities community has developed supportive resources that are important to asset revitalization initiatives that include the following:

- Long established affiliations with local university and community colleges for technical, scientific, and information technology training; with extensive local utility and workforce training facilities.
- Targeted business development efforts on large federal programs to significantly diversify the area's funding base and build infrastructure.
- Regional higher education includes WSU Tri-Cities and Columbia Basin College.

The region has supportive host communities that are familiar with the region's capabilities and technologies. The Tri-Cities established a community of industry and government entities that are working together and can be easily deployed to realize the vision of the Mid-Columbia Energy Initiative (MCEI) led by the Tri-City Development Council (TRIDEC). Visions and goals are as follows:

- Vision to become the suppler-of-choice for everything connected to Smart Energy (energy storage, integration of clean energy sources, energy transmission).
- Establish Mid-Columbia region as a "Center of Excellence" for research and development (R&D), demonstration and deployment of new energy technologies, and a center for component manufacturing
- Use local and regional energy resources to provide solutions to national energy challenges.
- Leverage R&D and commercialization expertise from Pacific Northwest National Laboratory (PNNL), WSU, Tri-Cities Research District, business entrepreneurs, and local energy companies to implement new energy technologies.
- Establish training and education programs through Columbia Basin College, WSU Tri-Cities and affiliates, and local labor to support national needs for utility and workforce training in clean/sustainable energy technologies.
- Support commercialization, technology transfer, and manufacturing of equipment designed for use in sustainable/carbon neutral energy production.
- Educate policy makers on local and national energy issues.
- Recruit like-minded leaders and organizations to make the Mid-Columbia a "hub" for energy in the Pacific Northwest.

- Be a leader in testing, installation, and operation of new Smart Energy technologies developed by PNNL and others, and in providing a test bed for the integration and distribution of energy from wind, solar, biomass, and other clean energies.
- Showcase recycling and conservation initiatives for commercial and residential energy consumption.
- Pursue local, state, and federal partnerships and funding support.
- Institute an adequately funded and organized program to market available land and buildings to attract new businesses to create new jobs and a tax base.
- Create a physical and intellectual environment so companies and workers can interrelate, technology transfer and product commercialization can develop, educational and training opportunities are available for professional and support workers, establish and support vertical and horizontal industry clusters, and serve as a focal point for technology-related community outreach activities.
- Work with state and federal offices to identify and create state tax incentives and federal funding support to encourage new sustainable energy/carbon neutral manufacturers in the region.

In addition, the Tri-Cities Research District is a center of technology invention and advancement in the Pacific Northwest. Designated by Washington's Governor as an Innovation Partnership Zone, the Tri-Cities Research District is recognized as a driving force fueling the region's economic growth. More than 7,000 workers are employed in the Tri-Cities Research District. It is home to PNNL, a national center for energy and environmental research. WSU Tri-Cities is located in the Research District providing new technologies and highly educated technical workforce, working in conjunction with PNNL. The Port of Benton and many of the world's largest engineering and construction firms, and more than 80 innovative and globally-competitive private businesses are located here to be near customers, with the intent to leverage each other's capabilities.

The Tri-Cities Research District features several unique facilities. The Applied Process Engineering Laboratory is a 90,000 square-foot-high technology business incubator. WSU's new Bioproducts, Sciences, and Engineering Laboratory is a collaborator with PNNL and is devoted to the scientific R&D and process engineering for bio-based product manufacturing, particularly of high-value byproducts from bio-based energy production processes.

The Mid-Columbia region plays an extensive role in providing energy needs across the Pacific Northwest:

- Forty percent of the state's total energy production and 100 percent of the wind energy is generated within 100 miles (7 hydropower facilities, 1 coal power facility, 7 natural gas facilities, 6 wind power hubs, and 1 nuclear reactor).
- Extensive regional energy infrastructure, including BPA, Energy Northwest (operator of the Columbia Generating Station nuclear power plant), railroad services, river barges, and multiple public utilities.

- Specialized workforce skills include nuclear and non-nuclear construction, facility management and operations, nuclear safety, and environmental remediation of hazardous and radioactive wastes.
- The Tri-Cities possesses a high concentration of educated and experienced, world-class nuclear and clean energy researchers.
- Training programs are available at the Volpentest Hazardous Materials Management and Emergency Response (HAMMER) Training and Education Center using blended-learning, hands-on activities, lessons-learned, and cutting-edge technology.
- PNNL has world-class scientific expertise that provides practical, high-value, and cost-effective solutions to a wide range of complex technical problems including energy. PNNL is a recognized leader in SmartGrid technology, large-scale energy storage R&D, and smart chargers.
- Cutting-edge regional science and technology research teamed with PNNL, WSU Tri-Cities Bioproducts, Sciences, and Engineering Laboratory, a world-class research center to focus on bioproducts and bioenergy.
- The Pacific Northwest SmartGrid Demonstration Project, Battelle, and DOE's National Energy Technology Laboratory have a cooperative agreement with BPA, 11 utilities and 5 technology companies to create approximately 1,500 jobs in manufacturing, installation, and operation of smart grid equipment, telecommunications networks, software, and controls.

2.2 WATER USE

All industrial processes, including electricity generation, fuel production, and biomass processing, use significant amounts of water. Attracting new industrial development requires that adequate water resources are available. It has been estimated that approximately 5,000 gallons per minute (gpm) of water will be required; however, a limited number of possibilities exist for that amount of water. Potential sources for a water supply include the development of groundwater and surface water with necessary water rights, or from water purveyors through a contract.

The Revised Code of Washington (RCW) 43.21A.064, "Powers and Duties – Water Resources," states that the Washington State Department of Ecology is responsible for the state water resources and for making decisions on future water resource allocation and use. Since much of the water in Washington already has been allocated or claimed, it is increasingly difficult to obtain new water rights. As a result, many individuals choose to make changes to existing water rights in order to meet new water needs, provided there are existing water rights available through a willing seller. Locally, transfers may be processed by the Benton County Water Conservancy Board, which maintains an information exchange regarding potential buyers and sellers of water rights within the county.

Potential developed water supply sources might include Energy Northwest, WSU, Battelle, and the city of Richland. Of these, only Richland is considered a water purveyor and the most capable of providing an adequate quantity of water. Additionally, the other potential sources would have more complicated water right issues to resolve.

The city of Richland has ample water rights for commercial and industrial uses. According to the city of Richland's *2010 Comprehensive Water System Plan*, the city draws upon the Columbia River and groundwater well fields to supply drinking water to its customers. The city also has standalone water systems that supply water for irrigation, industrial uses, and other governmental proprietary purposes to its customers without treatment. The city currently holds water rights for approximately 55,000 acre-feet/year and uses about 25,000 acre-feet/year. A water supply demand of 5,000 gpm is equivalent to 8,070 acre-feet/year.

The city's urban growth area (UGA) extends north of Horn Rapids Road, which is in the city limit (Figure 2-1). If the facilities in this report are located in the UGA, the city has existing infrastructure capable of meeting the water demand to that area. If the facility is located outside of the UGA, discussions with the city will be necessary to coordinate development of appropriate infrastructure. To ensure necessary agreements and possible infrastructure needs are addressed, discussions should be initiated with the city of Richland's Business and Economic Development Manager and the Director of Public Works.

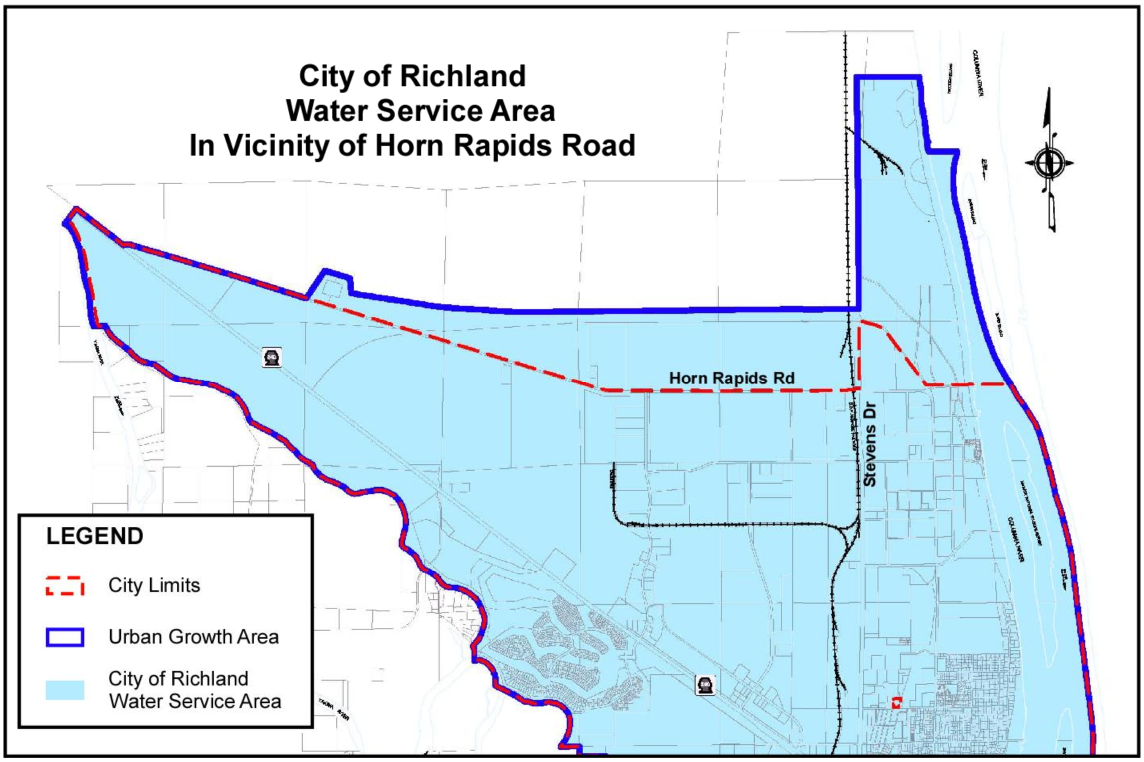

Figure 2-1. City of Richland Water Service Area.

3.0 ENERGY SOURCES AND TECHNOLOGIES

3.1 CONVENTIONAL POWER GENERATION

> **Conventional Power Summary**
>
> - Natural gas-fired gas turbines in either a simple cycle or combined cycle configuration are mature and can support both base load and peak power demands.
> - Natural gas-fired internal combustion engines offer a small capacity, scalable, power generation approach.
> - CHP architecture maximizes energy utilization and could support site industrial development by providing process heat and cooling.
> - Natural gas can be used to improve efficiencies and supplement power generation from renewable energy sources.

When considering development of new power generation facilities in the local region, conventional sources must be considered because of their cost effectiveness, technology maturity, reduced risk/field-proven performance, and ability to be deployed in the near term. Each of these criteria should be evaluated when considering new power generation development options. Sources in the local region that address most of these criteria include coal, hydroelectric, nuclear, and natural gas. Installation of a coal power plant does not meet the project's green energy objectives. Hydroelectric power is readily available in the Pacific Northwest and is a primary source of power; however, there are no plans to expand hydroelectric power in the region although the region has deep roots in the nuclear industry and a skilled nuclear workforce. As noted by the Northwest Power and Conservation Council[2] in the *Sixth Northwest Conservation and Electric Power Plan*, this leaves natural gas as the only conventional and practical energy source for new power generation opportunities in the Mid-Columbia region that can be operational in the near term. The remainder of this section describes various power generation architectures that utilize natural gas, discuss their potential benefits and limitations, and incremental development options that integrate clean energy options with natural gas.

3.1.1 Gas Turbines

There are several straightforward power generation architectures that could utilize the proposed natural gas line. Figure 3-1 shows a simple gas turbine cycle where compressed air is mixed with natural gas, burned in the combustor, and the exhaust gas drives a gas turbine to produce electricity. Simple gas turbine cycles have typical thermal efficiencies of 30 to 40 percent. A U.S. Energy Information Administration (EIA) study[3] that examined the average national levelized costs for new electricity-generating technologies in 2016 projected the cost for a simple gas turbine cycle to be $124.50/MWh when operating at a 30 percent capacity factor.

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[2] The Northwest Power and Conservation Council was formed by the Northwest states in 1981 in accordance with the *Pacific Northwest Electric Power Planning and Conservation Act of 1980*. The Council was formed to give the Pacific Northwest states and the region's citizen guidance in how growing electricity needs of the region are to be provided. The Act charges the Council with creating a power plan for the region. The purpose of the power plan is to ensure an adequate efficient, economical, and reliable power supply for the Pacific Northwest.

[3] www.eia.doe.gov/oiaf/aeo/electricity_generation.html

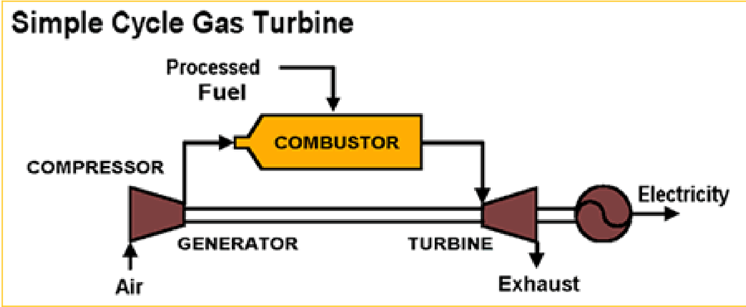

Figure 3-1. Simple Gas Turbine Cycle. [4]

A 30 percent capacity factor was utilized in the EIA study because gas turbines have the ability to be turned on with minimal startup time. As a result, gas turbines are frequently used to supply additional power in times of peak power demand. A wide range of gas turbine capacities exist in the market place, with General Electric (GE) offering models from 11 to 340 MW and Siemens offering 4 to 375 MW. As an example of a gas turbine that could be used in a simple cycle, the GE 6FA Heavy Duty Gas Turbine, can provide 77.1 MW of power with a 35.3 percent thermal efficiency and 24 minute start time to base load power[5].

3.1.2 Internal Combustion Engines

Another natural gas-based power generation architecture is internal combustion (IC) engines. While such units do not offer the power output capacity range of gas turbines, many of the other performance characteristics are similar or better (efficiencies, startup times). IC engines for power generation can be thought of as a larger (physically and number of cylinders), more powerful, natural gas-based version of the typical spark ignition engine found in automobiles. Typical industrial IC engines feature fuel-injection, turbo charging, and individual cylinder control to optimize engine performance.

A sample industrial IC engine for a power plant application is the GE J920, which has a 9.5 MW output power capacity, a thermal efficiency of 46 percent, and startup time of 5 minutes. Like a gas turbine, the short startup time makes the natural gas IC engine a good choice for addressing peak power demands. Industrial natural gas IC units typically lend themselves to a modular/scalable architecture, thus larger power output capacities can be achieved with multiple units. This scalability also makes IC engines a good option for achieving an output power value that might fall in-between the size of larger capacity gas turbines. Thus, a total output power capacity could be achieved without incurring the costs of larger gas turbine units that would operate less efficiently because they are not being used or are close to their maximum capacity.

In addition to power generation, natural-gas fired IC engines have applications that should be considered when evaluating industrial development in the Mid-Columbia region. GE has delivered more than 800 gas-fired engines for use in fertilizing greenhouses with CO_2 to enhance plant growth.[6] Under appropriate lighting and temperature conditions, if the greenhouse

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[4] www.eere.energy.gov/tribalenergy/guide/biomass_biopower.html
[5] www.ge-energy.com/products_and_services/products/gas_turbines_heavy_duty/6fa_heavy_duty_gas_turbine.jsp
[6] http://www.ge-energy.com/solutions/co2_fertilization_for_greenhouses.jsp

environment is supplied with supplemental CO_2, the resident plants will consume this CO_2 in the photosynthesis process, resulting in enhanced plant growth/yield.

The CO_2 is captured from the exhaust gases of the IC engine. Greenhouse CO_2 fertilization could be implemented as part of a biomass feedstock growth/supply plan if biomass combustion is considered for power generation onsite. In addition to utilizing the CO_2, the waste heat from the exhaust gases could be used as part of a greenhouse temperature control system or for heat in other site buildings.

3.1.3 Combined Cycles

While both the simple gas turbine cycle and natural gas IC engines are power generation architecture options that are well understood, field-proven, available in many different capacity options, and offer the ability to provide both base load and peak power, their maximum efficiencies are limited to less than 50 percent. The thermal efficiencies of the power generation system can be significantly improved when a gas turbine or IC engine cycle is combined with a steam power generation cycle (Rankine cycle). Figure 3-2 illustrates such a configuration that utilizes a gas turbine, called a combined cycle. Efficiencies of combined cycles are significantly higher than simple cycles because the waste heat from the gas turbine or IC engine is captured and used to create steam in a heat recovery steam generator (HRSG), which in turn drives a steam turbine generator. It is the utilization of the gas turbine waste heat to produce additional power that drives overall cycle efficiency higher. As examples of efficiency improvements, the GE 6FA Heavy Duty Gas Turbine increases from 35.3 percent in a simple cycle configuration to 55 percent in a combined cycle configuration.

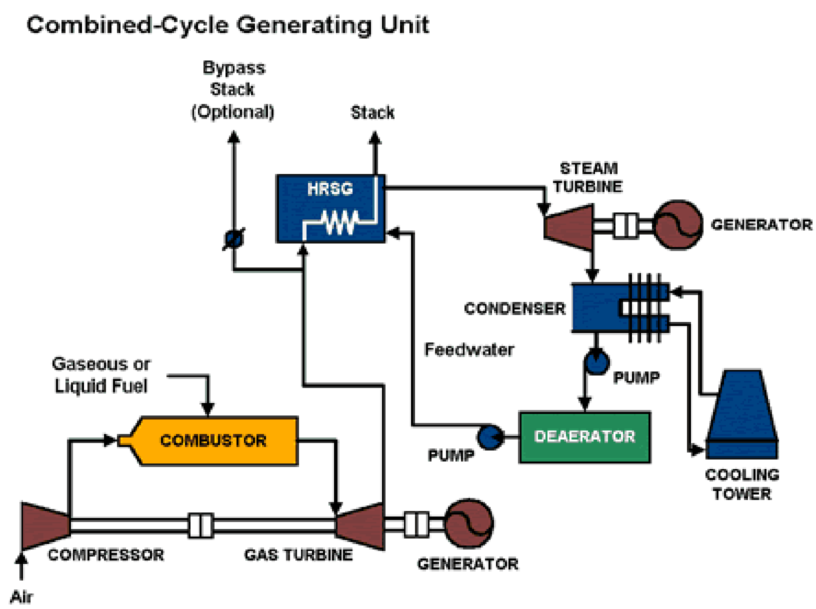

Figure 3-2. Sample Combined Cycle Configuration. [7]

[7] www.eere.energy.gov/tribalenergy/guide/biomass_biopower.html

3.1.4 Combined Heat and Power

The above configurations and associated example performance parameters assumed that the only output was electrical energy. With modifications, the combined cycle can be used to provide process heat or steam in addition to electricity. This type of configuration, shown in Figure 3-3, is called a Combined Heat and Power (CHP) or cogeneration configuration. Cogeneration references the generation of both heat and electrical energy from a single fuel source. As shown in Figure 3-3, the fuel source remains natural gas and the power generation technology that directly uses this fuel (the prime mover) is the gas turbine.

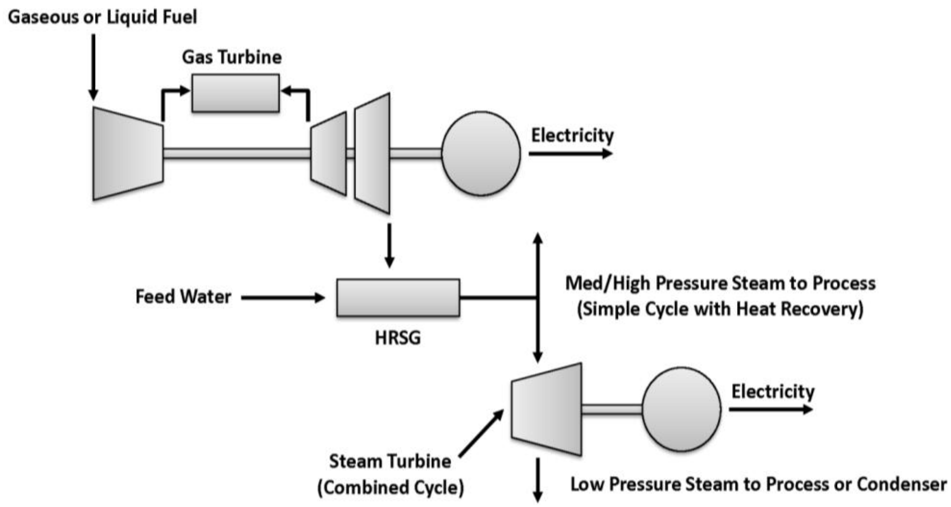

Figure 3-3. Sample Combined Heat and Power Configuration. [8]

The process heat or steam is obtained by bleeding off partially expanded steam from the steam turbine. The steam can be extracted at whatever pressure is required by the application/process that will be utilizing the steam. Example uses for process steam include heating water or air for residential or industrial heating or cooling, heating air for use in industrial drying, or utilizing the steam directly in a specific industrial process. Because energy can be extracted from the process as both electricity, via the gas turbine and the steam turbine, and heat via the exhaust heat from the gas turbine used to create steam, and/or using extracted steam for process heat, the result is a significantly increased use of input energy as compared to the simple gas turbine or IC engine cycles. Depending on the specific components in a CHP cycle, anywhere from 60 to 90 percent of the energy input is output as thermal or electrical energy. This is a significant increase in overall system efficiency as compared to simple power producing cycles where only 30 to 40 percent of the input energy is typically output as electrical energy and the rest is exhausted to the environment.

Utilizing process steam for industrial heating or cooling warrants further discussion due to its potential alignment with site industrial development. While the concept of using hot steam for a heating application is straightforward, the use of heat as part of a cooling application requires additional explanation. Cooling occurs through implementation of an absorption chiller into the

[8] http://www.epa.gov/chp/documents/catalog_chptech_gas_turbines.pdf

system. An absorption chiller utilizes the waste heat or process steam from either the gas turbine or steam turbine to drive a refrigeration cycle. An absorption chiller usually contains two fluids, typically water and lithium bromide. Waste heat or thermal energy from process steam is applied to a high pressure vessel (typically referred to as a generator) that contains a mixture of the water and lithium bromide. Adding heat causes the water to vaporize, resulting in a separation of the mixture into water vapor and liquid lithium bromide.

Liquid lithium bromide passes through an expansion valve and is used later in the cycle. Water vapor flows to a condenser where heat is removed, leaving high pressure water. Water pressure reduction occurs by passing through an expansion valve into an evaporator, where it absorbs heat from a separate water circuit. This heat exchange between absorption chiller water and the external water creates chilled water for use in building cooling equipment. The absorption chiller water once again vaporizes as part of the heat exchange. At this point the absorption chiller vapor is re-mixed with the low pressure lithium bromide and sent to the generator, where heat is applied and the cycle repeats itself. Note that in an absorption chiller, the waste heat or process steam and the generator replace the function of a motor and compressor in a typical vapor refrigeration cycle. The use of a combined cycle for power generation, heating, and cooling is referred to as tri-generation and can be a very effective means of energy utilization.

3.1.5 Steam Turbine

CHP architecture can be customized to meet site-specific needs. In addition to choices in the prime mover, the choice of steam turbine can impact system performance. Two types of steam turbines exist and the choice depends on whether the primary function of the system is to generate power or provide process heat or steam. Steam turbines can be condensing or non-condensing. A non-condensing steam turbine means that there is no liquid condensate in the steam as it expands through the turbine. The steam leaves the turbine as 100 percent vapor. In a condensing turbine, the steam leaving the turbine will not be 100 percent vapor (typically 90 percent vapor, 10 percent liquid). If a system's primary purpose is to provide process heat or steam, a non-condensing steam turbine is the best choice because as it passes through the turbine, whatever steam is needed for process is extracted, and the remaining steam is used to generate power. In other words, the available steam for use in power generation is completely dependent on how much steam is extracted for use in process applications.

No energy losses are incurred due to a post-turbine cooling and condensing process. If the primary purpose is to generate maximum power, the system needs a means for recycling steam after it has expanded through the turbine back to the HRSG so additional steam can be created. Thus, the expanded steam is cooled, condensed, and pumped back to the HRSG (see Figure 3-3). Energy losses are incurred in the condensing process; however, the system has the ability to generate a controlled quantity of power independent of any process steam needs because a known quantity of condensate and make-up water can be pumped back to the HRSG; therefore, a known quantity of steam and power can be generated. With the choices in prime mover and their scalability, many output power capacity options, steam turbine options, and the ability to satisfy base and peak power demands, implementation of CHP architecture in the Mid-Columbia region could support many land development options in an energy efficient fashion.

3.1.6 Natural Gas Integration with Renewable Energy Sources

When considering a combined cycle architecture (for power only or CHP), it is possible to integrate clean energy sources into the cycle. Renewable energy options that could be integrated into a combined cycle include concentrated solar thermal (CST),[9] photovoltaic (PV), biomass combustion, or wind. A sample combined cycle is shown in Figure 3-4, with the clean energy source being represented by the solar field.

Thermal energy generation from renewable sources, such as CST or biomass combustion, is integrated into a combined cycle power plant via a HRSG and the heat is used to create additional steam input to the bottoming cycle steam turbine. Electrical power integration from PV or wind can be integrated at the switchyard for transmission, at the switchyard to reduce the net parasitic load of the facility, or the gas turbine of the combined cycle power plant can serve as the spinning reserve or non-spinning reserve to firm wind and PV for dispatchability and grid integration.

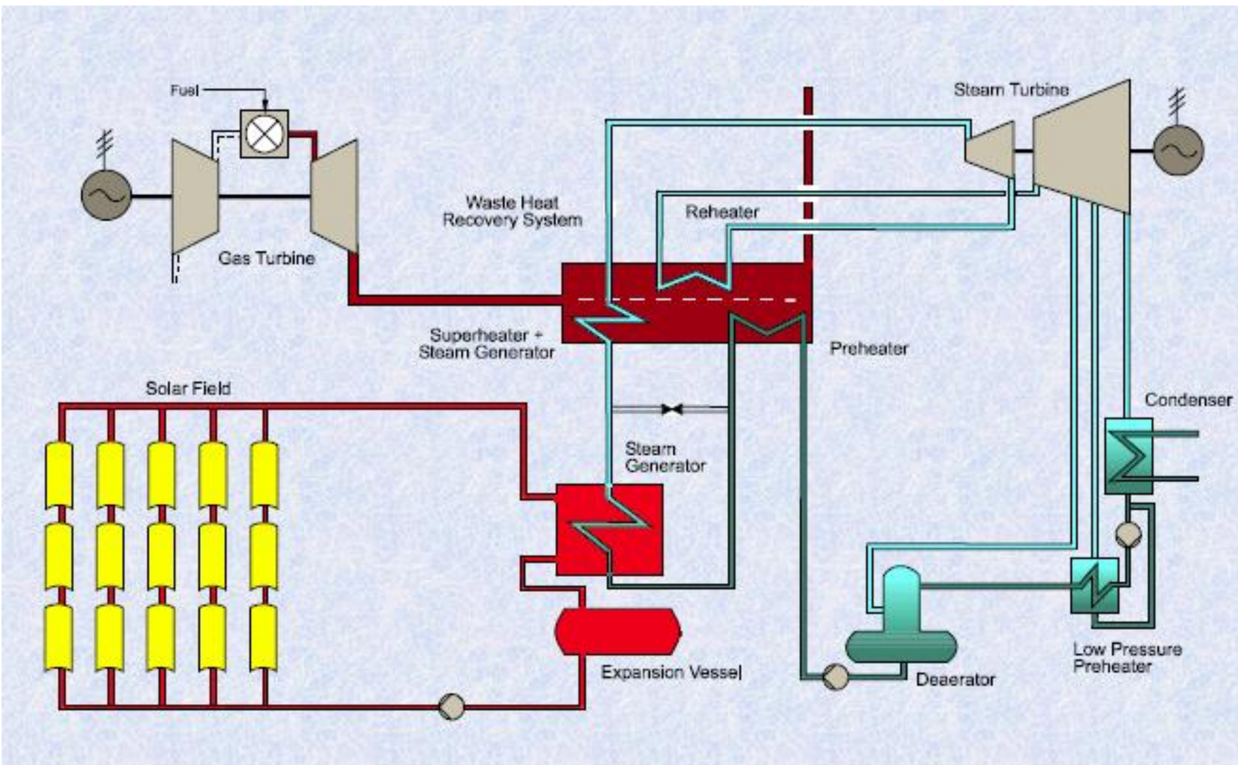

Figure 3-4. Sample Integrated Solar Combined Cycle Configuration. [10]

[9] CST refers to using concentrated solar radiation to create heat only, as in a rooftop hot water system or integrating a parabolic trough section into the bottoming cycle of a combined cycle power plant. CSP refers to the generation of electricity via concentrated solar radiation, typically via a HRSG to transfer heat from the thermal fluid to water to create steam, followed by steam expansion in a Rankine-cycle power block.
[10] Kelly, Hermann, and Hale, *Optimization Studies for Integrated Solar Combined Cycle Systems*, Proceedings of Solar Forum 2001 Solar Energy: The Power to Choose, April 21-25, 2001, Washington, DC, Copyright © 2001 by ASME.

Because many renewable sources depend on environmental conditions (biomass being an exception), integration with a gas turbine fueled by natural gas can be a way of supplementing power generation output when environmental conditions are unfavorable or as a means for providing additional power in times of peak demand. The short startup times of gas turbines make natural gas an excellent option for providing supplemental power during marginal environmental conditions (cloudy day, no wind) or during nighttime operation when considering solar energy. In addition to providing a means for generating power, natural gas can be used to improve steam conditions to optimize steam turbine performance. Natural gas could be burned to provide preheat (adding additional heat to the steam after it exits the boiler or HRSG) to the steam prior to it entering the steam turbine inlet.

Increasing the temperature of the steam prior to turbine inlet increases the overall efficiency of the steam (Rankine) cycle by increasing the energy output of the turbine. It also increases the steam quality (increased vapor content of the steam), which helps alleviate turbine blade degradation due to moisture (as opposed to vapor) impingement on the blades. Typical turbine steam inlet conditions for turbines utilized in a combined cycle power plant are 2,000 psi and 1,000°F. If environmental conditions result in steam generation at something less than these conditions, natural gas can be the energy source that brings the steam up to the desired pressure and temperature. The Solar Energy Generating Stations in the Mojave Desert in California use natural gas to compensate for environmental conditions and improve steam conditions.

Many factors that must be examined when considering integrating clean energy sources with conventional power generation methods. Some of these factors include the availability of fuel (solar intensity, wind conditions, availability of biomass feedstock), the pricing structure paid for power generation, the market for renewable energy credits (REC), and the levelized cost of electricity associated with each power generation architecture. Of these items, the levelized cost of electricity is the only item that is driven by the architecture choice. Undoubtedly, the cost of any clean energy option will be more than a conventional natural gas approach. Based on the EIA study referenced above, total system levelized costs (2009 $/MWh) for various architectures are: CSP - $311.8; PV - $210.7; Wind - $97; Biomass - $112.5, and Natural Gas Combined Cycle - $66.1. As expected, standalone clean energy options are significantly more costly than a conventional natural gas-fired combined cycle.

As a result of this cost difference, when a combined cycle that includes a renewable source is under evaluation, it may be beneficial to size the conventional power generation approach to meet primary power needs and the renewable source as a means for supplying extra power back to the grid or for meeting peak electricity needs (e.g., additional demand generated on a hot sunny day could be met with power generation from solar thermal or PV sources). The capital cost is cut by sharing components such as the power block and the switchyard, decreasing the levelized cost of energy (LCOE) for those components. An evaluation of all capital costs, payback periods, and marketplace information that includes power purchase pricing and REC market pricing must be completed before committing to a particular clean energy approach.

Considerable experience exists in completing detailed feasibility analyses that take the parameters described above into consideration. As an example, Lockheed Martin evaluated a power plant concept design that included both concentrated solar and biomass combustion components. As a result of marginal solar density in the geographic region under consideration and the power payment structure that was proposed by the utility, it was determined that the majority of power generation would need to be produced with the biomass combustor. The ensuing fuel costs and fuel availability made this an unfeasible architecture under the power pricing structure proposed. The number of parameters (environmental, technical, and economic) makes such analyses challenging; however, they are required prior to finalizing any concept design. The capability has been demonstrated to predict power generation capacities for particular architectures and couple this information with detailed cost models in order to evaluate potential plant design concepts. Such a feasibility assessment can be readily conducted if additional investigation is desired.

3.1.7 Path Forward

As the need for power increases in the Pacific Northwest, a multitude of flexible, mature, scalable, and affordable conventional natural gas fueled power generation options are available that should be considered. Gas turbines can be utilized in a simple cycle to provide base load, peak power, or with a steam turbine to improve input energy utilization and provide additional power. IC engines offer the same capabilities as the gas turbine, but in smaller capacities. The smaller capacity and modular form make them well suited to development plans that may have peak power demands or a need for future growth capacity. If regional industrial development comes to fruition, CHP options may be of significant interest because it can support industrial heat and steam needs as well as support building heating and cooling needs.

3.2 CLEAN ENERGY TECHNOLOGIES

World electricity use is expected to double between 1990 and 2035, with an increase of about 65 percent from 2009 to 2035 predicted by the EIA. In the United States, electrical use is predicted to grow approximately one-half percent/year for the foreseeable future.

Energy Sources

- Three viable clean energy sources are considered: natural gas, straw biomass, and municipal solid waste.
- These three sources provide flexibility and redundancy for an integrated approach to economic viability.
- The three sources can be used to produce combinations of end products including drop-in fuels, valuable chemicals, and electric power.

Coal-fired power plants supply about 48 percent of the United States power needs; however, the plants will begin to go out of service essentially without replacement over the next 10 to 50 years. Although new capacity can be developed using abundant domestic supplies of natural gas, growth in power demand and loss of aging coal-fired and nuclear infrastructure will create a shortfall in capacity in the United States with few other large alternative sources on the horizon. The *Sixth Northwest Conservation and Electric Power Plan* notes that the electricity load is expected to grow in the Pacific Northwest by approximately 1.4 percent/year between 2009 and 2030. This growth in energy demand must be met by a combination of existing resources, more efficient use of electricity, and new generation. Also, in the future, resource needs must consider capacity to meet peak load and the flexibility to provide within-hour, load-following, and regulation services.

The *Sixth Northwest Conservation and Electric Power Plan* notes that wind generation is the leading resource in the near term to meet clean energy portfolio standards in the Pacific Northwest; however, it also identifies that natural gas-fired plants, both combined-cycle turbines and simple-cycle turbines are cost-effective options for additional energy, capacity, and flexibility. The following sections evaluate clean energy technologies to meet emerging needs.

Figure 3-5 shows the scope of this report in terms of the applicability of clean energy pathways in the Mid-Columbia Region.

3.2.1 Biomass Resources

Although many biomass resources are discussed, the Mid-Columbia region's potential is dominated by one resource, wheat straw. In 2007, the region grew over 7 ½ million tons of wheat straw. This amount of wheat straw feedstock would be enough to manufacture over 300 Mgal of liquid fuel, or approximately 1,600 MWs of electricity from a base load plant. Of these two basic production processes, the economics are more favorable for making liquid fuels than for generating electricity. The current price of natural gas makes it profitable to make liquid fuels from natural gas and then to transition from gas to wheat straw as the straw process infrastructure develops in the region.

A fundamental assumption has been made to evaluate regional biomass resources: Irrigated crop land that can be used for food or pulpwood production would not be converted to biomass production or would revert back to food production because the energy produced would not be as valuable as food crops; therefore, the very rich irrigated land nearby is not considered a major source of biomass for energy. This extends to corn waste, referred to as stover, because it is useful as animal feed.

Figure 3-6 shows rail and road infrastructure, gas pipelines, rivers and other pertinent features of the region, as well as estimated wheat straw production by county, with each bale representing 200 thousand tons of annual straw production. The stacks of straw are scaled according to the size of the resource in each county and are located within the calculated trucking distance to the Port of Benton in the Tri-Cities area. The Port of Benton was used as an example because of its combination of transportation infrastructure, location within the region and potential for development. This area is dominated by wheat straw resources. There is an extremely fertile 150 mile stretch of dry land farming between Spokane, Washington and Pendleton, Oregon called the Palouse. Additional wheat producing districts are located in counties surrounding the Tri-Cities area; these counties are abundant producers of wheat.

To estimate the straw production, figures were used for wheat production from the United States Department of Agriculture, National Agricultural Statistics Service (NASS) 2007 Census of Agriculture data. More recent data is available but it is not as complete as that from 2007. The 2011 straw harvest was a particularly productive year and more land has been planted due to the prevailing higher grain prices in comparison to that from 2007. A bushel of wheat is defined as 60 pounds. The straw produced has been computed at a ratio of 1.67 lb straw/lb wheat, which was established by the University of Kansas.

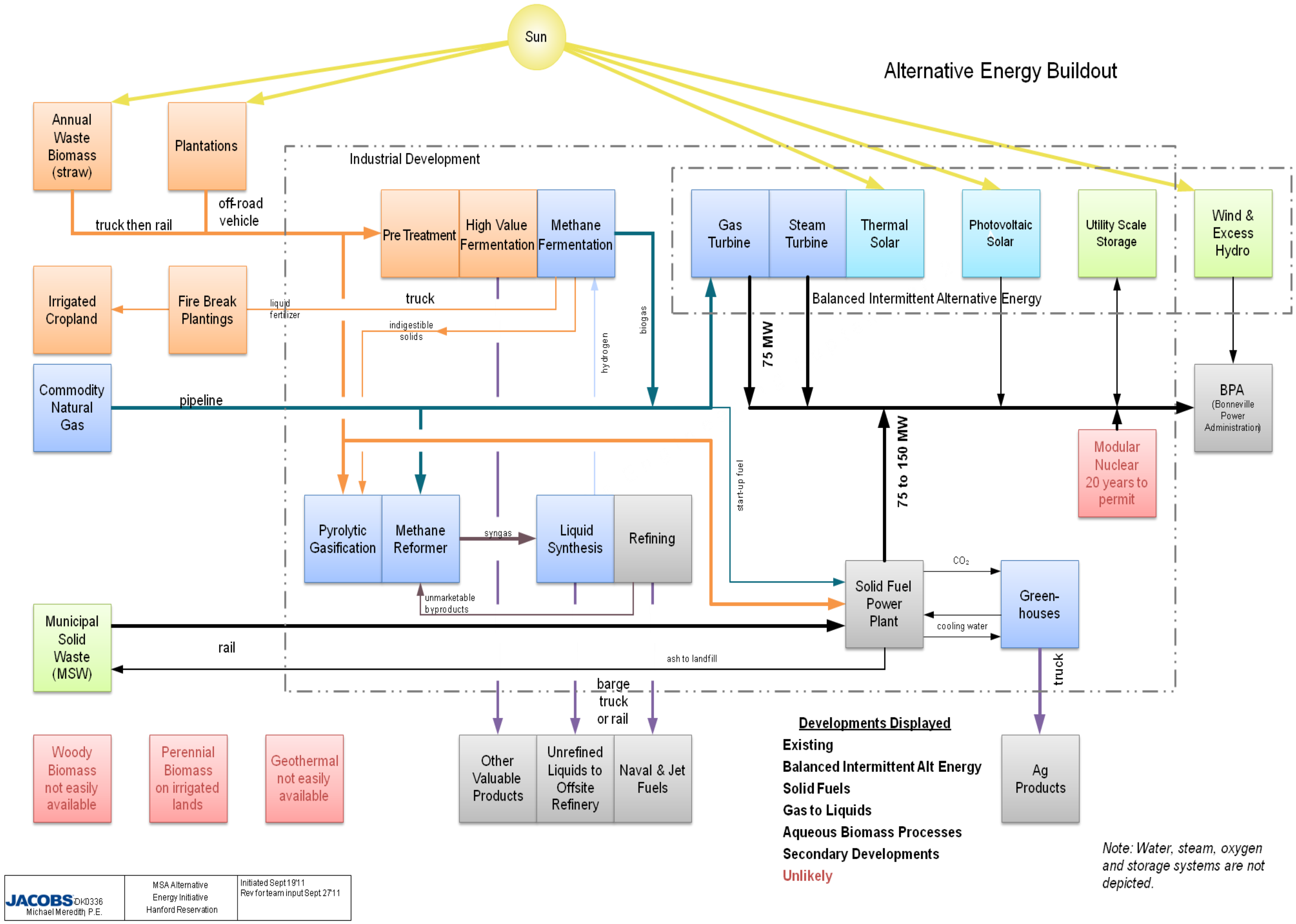

Figure 3-5. Clean Energy Pathways.

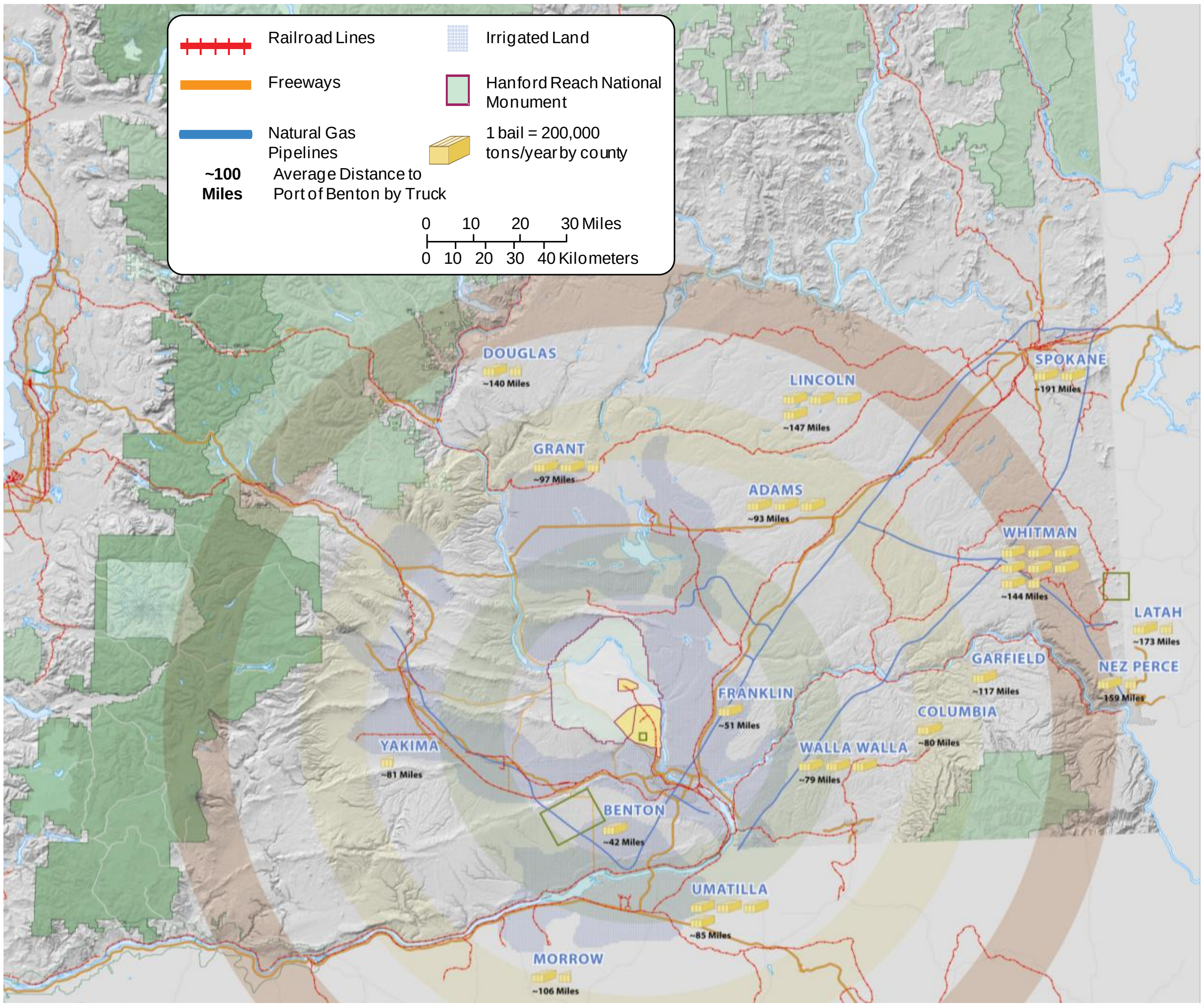

Figure 3-6. Availability and Transportation of Biomass Resources in the Region.

The ratio of 1.67 lb straw/lb wheat has been confirmed by a field study performed by WSU, which came up with a value of 1.70 lb straw/lb wheat.[11,12] A third confirmation was determined by using information from the Whitman County Extension office. The straw yield in Whitman County is between 3 and 4 tons/acre. Using a straw to wheat ratio of 1.67, the 2007 NASS data for Whitman County computed to 3.35 tons/acre in the middle of the range given.

There are about 7½ million tons/year of wheat straw available at projected costs between $65 and $100/ton delivered to the Port of Benton by truck. Figure 3-7 shows the availability of biomass wheat straw by county in the region versus cost of delivery. Favorable economics for use of the biomass wheat straw are noted by the area in the lower left-hand quadrant of the figure which includes the counties closest to the Port. The horizontal line (approximately 575,000 tons/year) is the amount of straw needed to support a demonstration plant of 22 Mgal/year, a solid fuel boiler of 75 MW, or a simple cycle plant using straw derived methane.

[11] *Wheat Straw*, SunGrant Bioweb, www.bioweb.sungrant.org, 2011.
[12] Edwin Donaldson, William Schillinger, and Steve Dofing, *Straw Production and Grain Yield Relationships in Winter Wheat*, Pacific Northwest Conservation Tillage Handbook, 2000, wsu.edu, Chapter 3.

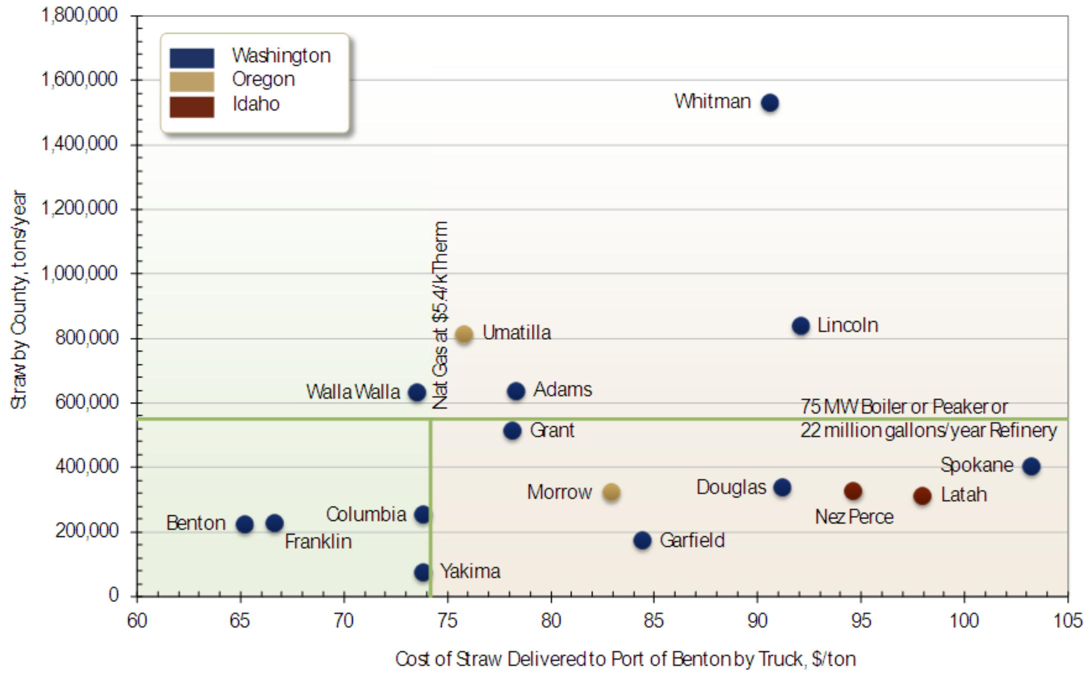

Figure 3-7. Biomass Availability and Cost.

A combined cycle plant of 75 MW using straw derived biogas would take approximately two-thirds of that amount of straw. The vertical line is the current British thermal unit (Btu) equivalent cost of natural gas. In summary, straw supplied from counties closest to the Port of Benton would be less expensive than natural gas if used in a boiler. Although this serves as a common basis for demonstration plants, the area is not limited to 575,000 tons/year. In the counties to the left of the line there is approximately 1,200,000 tons/year available.

The $65/ton figure is calculated for wheat lands closer to the Port of Benton and includes a $5/ton fee for farmers. Farmers prefer to burn the fields to make room for the next planting, but often cannot because of air pollution and fire regulations. A full explanation of the delivered cost of wheat straw is provided in Section 3.2.2.

The 7½ million tons of available straw could become more than:

- 1,000 MW converted in boilers to electricity in a base load plant, or;
- 300 Mgal of diesel equivalent, or;
- 1,600 MW if fermented to methane and processed through a combined cycle power plant.

For perspective, the state of Washington uses about 3,200 Mgal[13] of fuel a year and Navy ships use around 1,600 Mgal/year. Crude oil at $85/barrel is the equivalent of straw at $181/ton on a Btu lower heating value basis. It is not feasible to gather all the available straw and it will take time to build the supply chain of balers and truckers. The price if more distant straw might benefit from rail transport is discussed in Section 3.2.2.

[13] Motor Fuel Use, 1999.

3.2.1.1 Barley Straw

Barley is sometimes planted on the same land used for wheat. The barley production in the same counties for the same year was about 8.3 percent of the wheat production and the acreage harvested was about 8.4 percent of the wheat acreage. This data is supportive but not decisive in deciding to build a plant.

3.2.1.2 Alfalfa Straw

The Walla Walla valley is so well adapted for alfalfa that North American alfalfa seed production is centered there. The plants are allowed to dry out before harvest so they are not suitable for animal feed. There is about 25,000 tons/year of alfalfa straw available at a cost of approximately $65/ton in bales. Notice that although this is a significant amount of material, it is less than one-eighth of the wheat straw from Walla Walla County.

Other straws are insignificant except grass seed straw and corn stover. Grass seed straw is exported for animal bedding and feed in Asia and corn stover is fed to cattle; both resources are ruled out by the main assumption stated above.

Weeds and brush are often removed for fire prevention. These materials are difficult to bale for transportation and the yield per acre is very small. The supplier of these materials would probably not be able to pay for the expense of brush removal considering the price offered for biomass, but it would help.

3.2.1.3 Green Waste

Economically viable biomass products are discussed in the following sections. Other biomass resources include carrot tops, potato tops, surplus, and damaged crops; however, the quantity of these resources were found to be insignificant.

3.2.1.4 Woody Biomass

Woody biomass is not expected to be readily available in the Mid-Columbia region and therefore is not considered to be a significant feedstock for a biomass to energy plant. Fuel can be derived from wood gathered and preprocessed in the woods from thinning or logging slash or burnt wood; however, there are currently insufficient amounts of wood being removed from regional forests to economically justify a large biomass plant. Also, in the Pacific Northwest, the woods are almost predominantly softwood.

The main landowners are the U.S. Forest Service, Washington Department of Natural Resources, and the Indian Nations. Yakama Nation currently sells their biomass to the Boise Cascade Pulp Mill in Wallula, Washington. If woody biomass were available, it would be more economical to build power plants near the feedstock resource. Wood from saw mills and other processing plants is not given consideration because it is already consumed by existing power plants.

3.2.1.5 Poplar Plantations

Poplar plantations require irrigation or a high water table. This resource could provide the wood needed for a few megawatts (insignificant amount) of power generation at prices below straw. Poplar plantations have been established within 50 miles of the Port of Benton for pulp wood and ethanol. If, in the future the wood is not used for those purposes, it could become available to another clean energy facility.

3.2.1.6 Trees Needing No Irrigation

The MegaFlora™ tree is a mixed genetic entity with cells containing the genetics of both black locust and Paulownia trees in its stem; the Paulownia trees grow in Richland. Black locust trees have survived without water since 1943 in the area. Black locust produces its own nitrogen fertilizer from root nodules and can tap deep water tables.

Extraordinary productivities reaching 33 Oven Dry (OD) tons/acre/year have been suggested for this tree, but it has not been studied in Central Washington. Assuming normal growth, the area needed to produce 10 MW or 3 Mgal/year of liquid fuels would only be 1.6 square miles. This is indicated by the smallest green squares on the maps. WSU is agreeable to planting and studying test plots of unirrigated trees on or near their Tri-Cities campus. A suitable research grant would need to be proposed, vetted, and approved.

3.2.1.7 Fruit Prunings and Grape Pomace

These materials have not been given consideration as the basis of a biomass-to-energy plant because they yield a relatively minor amount of energy – roughly 1 MW of equivalent power. Prunings produce a lot of organic nitrogen that easily become nitrogen oxide (NOx) emissions in combustion, but would be helpful as a nitrogen source in the fermentation to methane process.

3.2.1.8 Red Liquor

The two sulfite pulp mills in Washington State produce large quantities of red liquor. Red liquor is a dissolved woody biomass from which cellulose has been extracted. Sulfite mills do not have the foul odor of pulp mills. Each mill produces about 600 OD tons of liquor/day which is concentrated to 50 percent solids. Their liquors can be readily fermented to ethanol or other substances. Red liquor would make a good fertilizer for wheat land because it contains ammonia, sulfur, and soil stabilizing lignin. The pulp mills would like to eventually abandon their red liquor recovery boiler and find a use for the liquor. The mills value the liquor at $100/dry ton for its heat and sulfur content. The ammonia content is destroyed in the boiler.

3.2.2 Transportation Systems

3.2.2.1 Trucking

Trucking is the current method for transporting baled straw, hay, and all other biomass in this area. Straw is the predominant source of biomass and baling of straw is the only method of preparation for shipment in current practice. The discussion of the biomass costs centers around the trucking of baled straw. Other transport possibilities will be discussed later.

The following economic information was provided by wheat farmers in the Palouse area who contract to harvest, bale, and truck straw and hay for other farmers.

An allowance of $5/ton[14] to the farmer and $10/ton for unloading and stacking the trucks should be added to the $50.11 straw cost calculated in Table 3-1, which results in a total of 65.11/ton straw delivered and stored. The 42 miles is an estimate of the truck distance from the straw source to a hypothetical plant near the Port of Benton.

Straw may be purchased at the farm site or on a delivered basis. An assumption can be made that the straw will be procured on a delivered basis. This eliminates the need for the plant owner to manage the harvesting and transportation. It also means a bonus of $12/ton for straw suppliers in Benton and Franklin counties. If straw is bought on the basis of delivered and stacked at the central processing site near Port of Benton, a judgment has been made that sufficient raw material will be available to feed a demonstration plant if the feedstock was offered at $73/ton. This will ensure that straw from Benton and Franklin counties, in addition to closer areas in Walla Walla and Umatilla counties will provide a sufficient amount to supply 550,000 tons/year. At this time, the cost of natural gas on an equivalent Btu basis is $75/ton; so the economics are favorable for the transportation and use of wheat straw over short distances.

It will take some time for the farmers and their contractors to develop the necessary logistics and infrastructure. This would include the purchase of more trucks and balers and the employment of more people. It is also important that natural gas be available to operate the plant in case of any raw material shortfalls.

There are several ways to lower the cost of straw collection:

- Receive state or county permission for wider and taller loads
- Use double trailers rather than single flat trailer
- Convert the trucks to dual fuel natural gas and diesel.[15]

3.2.2.2 Rail

The richer wheat lands of the Palouse, particularly Whitman County, are over 100 miles by road from the Port of Benton. Figure 3-6 shows the rail infrastructure of the more distant wheat lands. The Palouse is well served by rail.[16] The Port of Benton also has a well developed rail system.

Using current railroad technology to move straw over the distance from the Palouse area to the Port of Benton would be too expensive to play a part in a workable value proposition. Using common box cars or flat cars to carry low-density loads over relatively short (by railroad standards) distances of 100 to 200 miles would produce costs as high or higher than long-range trucking, making electricity or fuels produced more expensive than expected market prices.

The Tri-City and Olympia Railroad Company, which operates freight rail in the Tri-Cities area, has investigated existing technologies that would potentially lower the cost of straw transportation and allow biomass processing operations to take full advantage of available resources in the region. Several potential paths are available in intermodal and light weight railcar technology that would allow operations a greatly reduced cost per ton delivered.

[14] Daniel O'Brien and Ron Madl, *What to Consider with Cellulosic Biomass Harvest*, 2009 Kansas Wheat District Seminar presentation.
[15] Federal Tax Credits for Vehicles, CNG Fueling Infrastructure and CNG Fuel, www.firmgreen.com, 2005.
[16] Washington State Department of Transportation, *2010 Washington State Rail System*, rail.wsdot.wa.gov.

Table 3-1. Straw Values by County.

Wheat Straw Production																	
Source of Data		USDA National Agricultural Statistics Service 2007															
Straw Yield	lb/lb grain	1.67															
County	text	**Benton**	**Franklin**	**Walla Walla**	**Columbia**	**Yakima**	**Umatilla Or**	**Grant**	**Adams**	**Morrow Or**	**Garfield**	**Whitman**	**Douglas**	**Lincoln**	**Nez Perce**	**Latah**	**Spokane**
Acres Harvested	acres/yr	**94,268**	**76,863**	**190,973**	**77,970**	**20,427**	**303,203**	**145,979**	**262,101**	**170,060**	**68,447**	**457,973**	**157,898**	**313,441**	**106,270**	**91,834**	**140,746**
Bushels Harvested	bu/yr	**4,512,161**	**4,584,764**	**12,661,018**	**5,095,533**	**1,519,644**	**16,284,987**	**10,295,197**	**12,765,373**	**6,449,631**	**3,482,031**	**30,592,763**	**6,760,910**	**16,754,595**	**6,581,267**	**6,279,048**	**8,115,549**
	tons/yr	135,365	137,543	379,831	152,866	45,589	488,550	308,856	382,961	193,489	104,461	917,783	202,827	502,638	197,438	188,371	243,466
Straw	tons/yr	226,059	229,697	634,317	255,286	76,134	815,878	515,789	639,545	323,127	174,450	1,532,697	338,722	839,405	329,721	314,580	406,589
(Whitman Co. Extension said to expect between 3 & 4 tons/acre)	tons/acre	2.40	2.99	3.32	3.27	3.73	2.69	3.53	2.44	1.90	2.55	**3.35**	2.15	2.68	3.10	3.43	2.89
Costs																	
Remuneration for Farmer	$/ton	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**
Swathing	$/acre	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**	**10.00**
	$/ton	4.17	3.35	3.01	3.05	2.68	3.72	2.83	4.10	5.26	3.92	2.99	4.66	3.73	3.22	2.92	3.46
Baling	$/bale	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**	**12.00**
	$/ton	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Stacking	$/bale	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**
	$/ton	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Unloading & Stacking at Hanford	$/bale	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**
	$/ton	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Truck Load	bales	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**	**48**
	tons	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20	19.20
Average Distance to Hanford	miles	**42**	**51**	**79**	**80**	**81**	**85**	**97**	**93**	**106**	**117**	**144**	**140**	**147**	**159**	**173**	**191**
Cost for Truck, Trailer & Driver	$/loaded mile	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**	**5.00**
	$/load	210	255	393.5	399	405.5	423.5	485	465	530	585	720	700	735	795	865	955
	$/ton	10.94	13.28	20.49	20.78	21.12	22.06	25.26	24.22	27.60	30.47	37.50	36.46	38.28	41.41	45.05	49.74
	$/ton/mile	0.26															
Total Cost Delivered at Hanford	$/ton	65.11	66.63	73.51	73.84	73.80	75.77	78.09	78.32	82.87	84.39	90.49	91.12	92.02	94.63	97.97	103.20

One concept, called Roadrailer, uses road-going truck trailers equipped to mount railroad wheels, and can be switched rapidly from road to rail without the use of flat cars or cranes. Loaded cars could be driven by road to loading points and mounted onto road wheels by driving the trailers over track areas paved to match rail height. Cars are then raised to match steel wheel height, the rail wheels are rapidly attached, and the load is hauled away. The process can be reversed at the destination with minimal handling or difficulty. Roadrailer cars are extremely light in comparison to conventional railcars, and would allow very long unit trains, possibly as long as 200 cars, to be operated economically.

Although analysis is still ongoing, it is probable that rail transportation using advanced technologies such as Roadrailer over distances of 100 to 200 miles could match or provide better delivery costs of truck transportation, even over its shorter optimum distances, making growth of a biomass-based industry to its full potential in the region practical. Figure 3-8 shows the Roadrailer wheel system technology.

The cost of rail could be reduced by the following developments:

- Hydraulic compaction at the rail sidings
- Curtained rather than solid side wall container design
- A tarped train car-sized pallet system rather than a container
- Conversion of locomotives to compressed or liquefied natural gas.

Figure 3-8. Roadrailer Wheel System.

3.2.2.3 Barge

A barge dock exists at the Port of Benton in Richland. There are 28 grain elevators with barge loading facilities from The Dalles, Oregon to Lewiston, Idaho, but the grain terminal at Almota, Washington and the container dock at the Port of Lewiston are best suited to tapping the Latah and Nez Perce counties in Idaho and Whitman County in Washington. The low density of straw however, limits loads to 1,540 tons rather than the 3,000 ton weight limit of the barge. If it were compacted at the Port of Lewiston to twice the ordinary bulk density of a bale and put into containers, straw from Whitman County would be only $65/ton delivered and stacked. This is comparable to straw from Benton County. Straw compactors are used for rye grass straw exported to Asia. The Tidewater Barge Company noted that MSW from Clark County in Washington is compacted into containers and sent by barge up the Columbia River to an Oregon landfill using the Boardman dock. Tidewater Barge recommended using rail for product transportation until such time as economics are favorable to maintain dedicated barges of 42,000 tons busy.

The cost for a barge between any ports on the upper Columbia or Snake rivers is $20,000/round trip for 1,500 tons of dry straw bales, or 3,000 tons of bales compacted into containers. This mode of transportation needs to be developed and tested before being relied upon to build a plant.

3.2.3 Biogas

Purified biogas may be injected at one point on a natural gas pipeline and an equivalent amount of energy removed at another. A dedicated clean energy pipeline can carry syngas or biogas. Pipeline is the least expensive way of delivering fuel. A regional company currently pays the transportation price of $0.40/MM Btu, which is equivalent to straw transported for $2.50/ton. Biomass fermentation plants located nearer the sources of straw possessing water resources and on a natural gas pipeline such as Lewiston, Walla Walla, and Moses Lake would make economic sense. During winter and spring, water may be available from the Palouse River at Colfax and the Umatilla River at Pendleton. This would lower the cost of some straw to well below $65/ton. The technology for gas purification and compression is well known. Investigating the feasibility of remote generation of biogas is worth further consideration.

3.2.3.1 Off-Road Vehicles from Adjacent Plantations

If the source of biomass is close and can avoid being carried along public highways, the cost of transportation can be very low and the need for baling (or grinding in the case of wood) eliminated. There are other methods of preparing fuel before shipment to reduce bulk density, moisture, or spoilage.

3.2.3.2 Solar Drying

A solar dried pile occurs naturally with straw, so this discussion concerns woody biomass. Dry woody biomass does not degrade and is not prone to spontaneous combustion as is undried biomass. These characteristics require biomass to be spread in layers less than 1-inch thick during the dry season. The pile is gradually built up over the season and is tarped until use in the wet season. This procedure is being investigated at a woody biomass plant but has not been implemented.

In the Mid-Columbia region the dry season never entirely ends, so covering the biomass with tarps is not required. Woody biomass may be preserved in dried piles for the year. At rail sidings near the forests east of the Cascade Mountain Range, this means of preserving woody biomass is used until it is convenient to fill an entire train.

The cost for handling and spreading of woody biomass is about $10/ton with a capital cost of about $500,000 per site excluding the value of land. The amount of land required is about 30 acres for 300,000 OD tons of woody biomass.

3.2.3.3 Pelletizing

Straw can be densified into pellets for shipment.[17] However, this densification process requires large amounts of electricity and heat that is not available at farms. Straw still needs to be baled and transported by truck to central locations and then pelletized for shipment by barge or rail. Cursory analysis indicates that pelletizing will not offset shipping costs to justify the process. A system that would pelletize straw as it was harvested would be more helpful, provided it did not consume too much additional transportation fuel.

3.2.4 Aqueous Treatment for Densification

The bulk density of straw can be greatly reduced through chemical treatment. Straw can be wilted by alkali, acid, or hot water and oxygen. These treatments also dissolve carbohydrates into the water used to treat them.

Aqueous treatments require large amounts of water, tankage, and possibly heat normally not available at farms; therefore, straw would still need to be baled and transported by truck to central locations for processing; however, water is not available at all times of the year. Aqueous pretreatments before shipment require about 1 ton of water/ton of biomass. This densification does not increase the biomass shipping capabilities since the added weight of water offsets the reduced bulk density of the straw.

3.2.5 Pyrolysis

Heat treatment of straw can reduce its mass and bulk for shipment. The available technologies known are technically or economically not viable for the reasons given below:

- Low temperature syngas (methane rather than hydrogen) requires pipelines to carry gas. Biomass pipeline infrastructure is not likely to be developed in the region.
- Pyrolysis Oil[18,19,20] - Cannot be stored because it repolymerizes[21] and is corrosive

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[17] Agri Pack Quotation provided to Michael Meredeith, Pellet Systems International, 2011.
[18] N. Bech, P.A. Jensen, and K. Dam-Johansen, *Ablative Flash Pyrolysis of Straw and Wood: Bench-Scale Results*, Technical University of Denmark, Department of Chemical Engineering, CHEC Research Centre, Lyngby, Denmark.
[19] Samy Sadaka and A. A. Boateng, *Pyrolysis and Bio-Oil*, Agriculture and Natural Resources, University of Arkansas, Division of Agriculture.
[20] Young-Kwon Park, Jonng-Ki Jeon, Seungdo Kim, and Joo-Sik Kim, *Bio-Oil from Rice Straw by Pyrolysis Using Fluidized Bed and Char Removal* System, American Chemical Society, Division Fuel Chemical, 2004.
[21] A.V. Bridgewater and G.V.C. Peacocke, *Fast Pyrolysis Processes for Biomass*, Renewable & Sustainable Energy Reviews, Bio-Energy Research Group, Aston University, Birmingham, UK, 2000.

- Charcoal – Catches fire spontaneously (pyrophoric)
- Torrefication (toasting) of material – Requires a plant and a pelletizing mill.

Pyrolysis oil, charcoal, and torrefied material also cannot be fermented and are harder to gasify than plain straw.

3.2.6 Making Liquid Fuels via Syngas

A plant that makes liquids from gas is called a gas-to-liquid (GTL)[22] plant. The focus will be on naval and jet fuels[23] primarily because the DOD is supporting efforts to create green fuels and fuels independent from petroleum. Currently only the Fischer-Tropsch process is suitable for making naval and jet fuels. The Fischer Tropsch process makes a broad distribution of linear hydrocarbon molecules from a mixture of carbon monoxide and hydrogen called syngas. The major process steps are:

- Generation of syngas
- Water-gas shift to make more hydrogen if needed
- Fischer Tropsch (catalytic synthesis)
- Distillation into products, heavies and lights
- Hydrocracking of heavies which consumes hydrogen
- Hydrotreating of lights which consumes hydrogen.

Conversion of Energy Sources to Products

- Straw biomass or natural gas can be profitably converted to jet fuel – dual feedstock provides a hedge against natural gas process variations and biomass supply variations.
- Straw biomass can be profitably converted to high value chemicals.
- Natural gas, straw biomass, or municipal solid waste can be converted to electrical power.
- Multiple conversion process plants can share infrastructure at the site to reduce costs.

There are three possible feedstocks for making syngas: natural gas, biogas, and straw. These may be mixed to produce ideal ratios of hydrogen and carbon monoxide. Natural gas is almost pure methane. Syngas can be made from natural gas through reaction with oxygen in a process called auto-reforming. This produces a gas with 2½ moles of hydrogen per mole of carbon monoxide:

$$4CH_4 + O_2 + 2H_2O \rightarrow 4CO + 10H_2.$$

The Fischer Tropsch reaction, however, takes about two parts hydrogen to one part carbon monoxide by the reaction:

$$CO + 2H_2 \rightarrow (CH_2) + H_2O.$$

[22] *Gas to Liquids*, Chemlink, Australasia publications, www.chemlink.com.
[23] Detail Specification, *Fuel, Naval Distillate*, Department of Defense, 2006.

Syngas from natural gas has an excess of hydrogen. Syngas in a one-to-one ratio of hydrogen to carbon monoxide may be made by auto-reforming biogas which contains methane and carbon dioxide by the reaction:

$$2CH_4 + O_2 + CO_2 \rightarrow 3CO + 3H_2 + H_2O.$$

A process that derives 25 percent of its methane from biogas and the rest from natural gas will have the ideal 2:1 ratio of hydrogen to carbon monoxide and not require the water gas shift step. There is an option of reforming methane indirectly, in which fuel burning in air transmits its heat through a heat exchanger to the methane. This would allow a greater proportion of biogas to be used as that fuel and would avoid the need to make oxygen.

The third method to produce syngas is the gasification of cellulosic biomass such as straw by the reaction:

$$(CH_2O) \rightarrow CO + H_2.$$

This reaction has the 1:1 ratio of hydrogen to carbon monoxide. Straw gasifies very quickly. One can observe the gas as the flames that burst from a bundle of straw thrust into a fire. The gasification is self-sustaining via heat from the combustion of its own gas in air.

3.2.6.1 Capital Costs for a Gas-to-Liquid Plant

Three reference points provided by Jacobs Engineering were used for estimating the capital costs of a GTL plant:

- Jacobs London office recently performed a study for a European client and concluded that a natural GTL fuels plant costs about $400 million for a 2,100 barrel/day capacity.
- TRI Incorporated estimates that their process for woody biomass to Fischer-Tropsch fuels would cost $300 million for a plant that consumes 1,000 OD tons/day of woody biomass which would yield 1,400 barrels/day.
- Rentech estimates it will cost $600 million for a 2,000 barrel/day plant based on their plans to build a plant at Sault St. Marie, Ontario, Canada.

NOTE: *These prices are all indicative. The capital cost includes the installed process through liquid fuels but does not include site development, transportation systems, and owner's costs. All three sources agree that the plant capital may be scaled by the 0.6 exponent.*

TRI Incorporated and Rentech agree on a yield of 1.35 barrels/ton of woody biomass, which translates to 0.96 barrels/ton of straw or retention of 47 percent of the lower heating value of the original material. The plants generate their own electricity from steam turbines and are able to produce about 25 MW when the rest of the plant is not producing liquid fuels.

A demonstration plant has been examined that would be capable of producing 1,446 barrels/day, which is equivalent to the natural gas needed to produce 75 MW of power at 31 percent efficiency. Scaling all three projects to the same size results in the following capital costs:

- TRI Incorporated $313 million
- Jacobs London $320 million
- Rentech $494 million

Until additional engineering studies are performed, including site-specific vendor proposals, it is not possible to determine which number is the more accurate. The average value of the high and the low ($403 million) will be used for the capital costs and economic comparisons with an accuracy of ±35 percent.

The current cost of jet fuel and other similar fuels is approximately $3/gallon[24,25,26,27,28,29], but in the last 5 years it has been very volatile from $1 to $4/gallon as can be seen from the U.S. Energy Information Administration's chart (Figure 3-9).

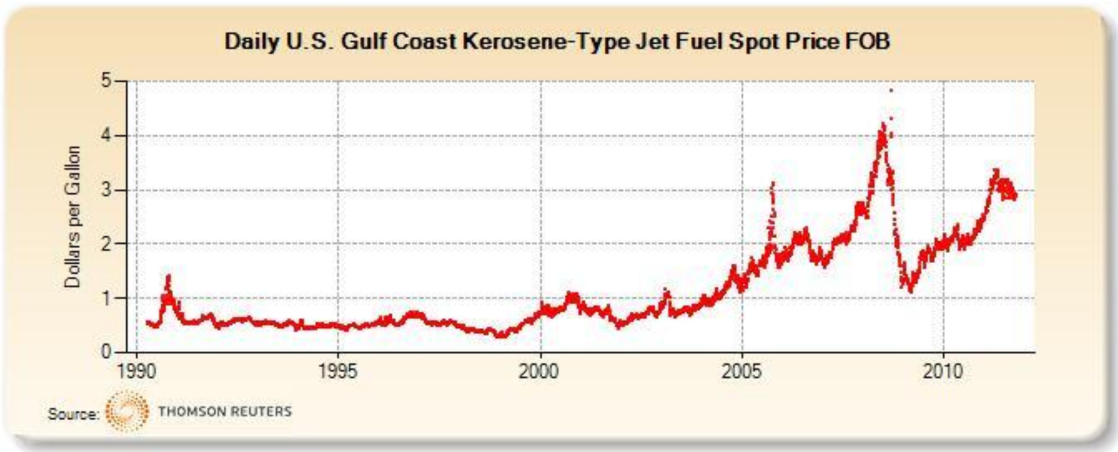

Figure 3-9. U.S. Gulf Coast Kerosene-Type Jet Fuel Spot Price FOB ($ per gal).

Military fuels have exhibited similar cost trends.[30] Operating 340 days/year, the value of the products would be $67 million/year at $3/gallon. The cost of straw to feed the plant would be $40 million/year. Natural GTL plants are reported to be more efficient (53 percent versus 47 percent) than biomass.[31,32,33,34,35] This may be because they have been built at a much larger scale. If so, an operation with natural gas may cost 25 percent less or only $30 million/year. It can be assumed that the plant will employ 100 people at an average rate of $100,000/year for

[24] *Jet Fuel Monthly Price – US Dollars per Gallon*, U.S. Energy Information Administration, www.eia.gov, 2011.
[25] Bloomberg New York Harbor 54-Grade Jet Fuel Spot Market Price Prompt, www.bloomberg.com, 2011.
[26] US Gulf Coast Kerosene-Type Jet Fuel Spot Price Chart and Data, www.ycharts.com, 2011.
[27] *Jet Fuel Price* Monitor, IATA Economics, www.iata.org, 2011.
[28] US Gulf Coast Kerosene-Type Jet Fuel Spot Price FOB (Dollars per Gallon), U.S. Energy Information Administration, www.eia.gov, 2011.
[29] Petroleum & Other Liquids, Spot Prices for Crude Oil and Petroleum Products, U.S. Energy Information Administration, www.eia.gov, 2011.
[30] *DOD Fuel Costs vs. Commercial and Crude Oil Price* and *DOD Fuels Costs vs. Crude Oil Costs*, Department of Defense Fuel Spending, Supply, Acquisition, and Policy, Congressional Research Service.
[31] Dominik Unruh, Kyra Pabst, and Georg Schaub, "Fischer-Tropsch Synfuels from Biomass: Maximizing Carbon Efficiency and Hydrocarbon Yield," American Chemical Society Publications, 2010.
[32] K. J. Ptasinski, T. Loonen, M. J., Prins, and F. J. J. G. Janssen, *Energy Analysis of a Production Process of Fischer-Tropsch Fuels from Biomass,* University of Eindhoven, Department of Chemical Engineering, Netherlands.
[33] *Products from Syngas – Fischer-Tropsch Synthesis Products,* SunGrant Bioweb, www.bioweb.sungrant.org.
[34] Anthony Andrews and Jeffrey Logan, *Fischer-Tropsch Fuels from Coals, Natural Gas, and Biomass: Background and Policy,* CRS Report for Congress, Congressional Research Service, 2008.
[35] *2nd Generation Biomass Conversion Efficiency*, McGill University, Montreal, Quebec, and IATA.

wages and benefits. The payback with current prices would be greater than 10 years. The financial viability would be improved if there is a reliable premium attached to the fuel for:

- Carbon neutral benefits
- Non-petroleum feedstock
- Regional employment and improved income to agricultural community
- Ultra low-sulfur content
- No potential disruptions of maritime commerce
- Retention of investment and capital in the United States.

This is an active area of R&D and improved economics at this scale will occur.

Figures 3-10 through 3-12 show comparisons of input cost and output values for standard biomass and electricity plants, the biogas-to-liquids demonstration plant, and the biogas-to-liquids full size plant.

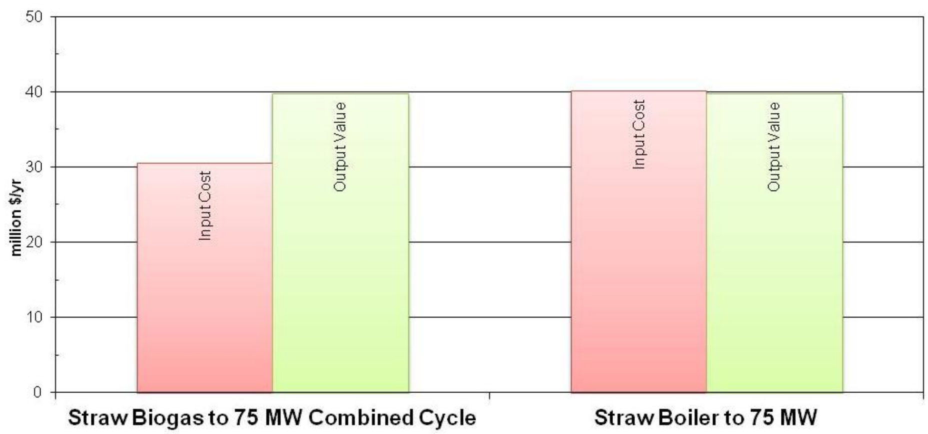

Figure 3-10. Electric Plant Value Propositions.

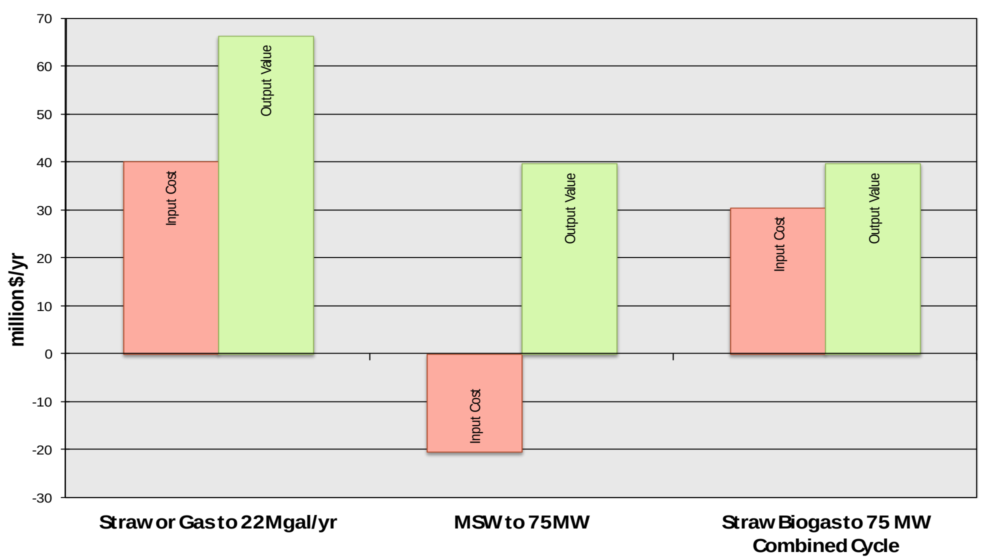

Figure 3-11. Demonstration Plant Value Propositions.

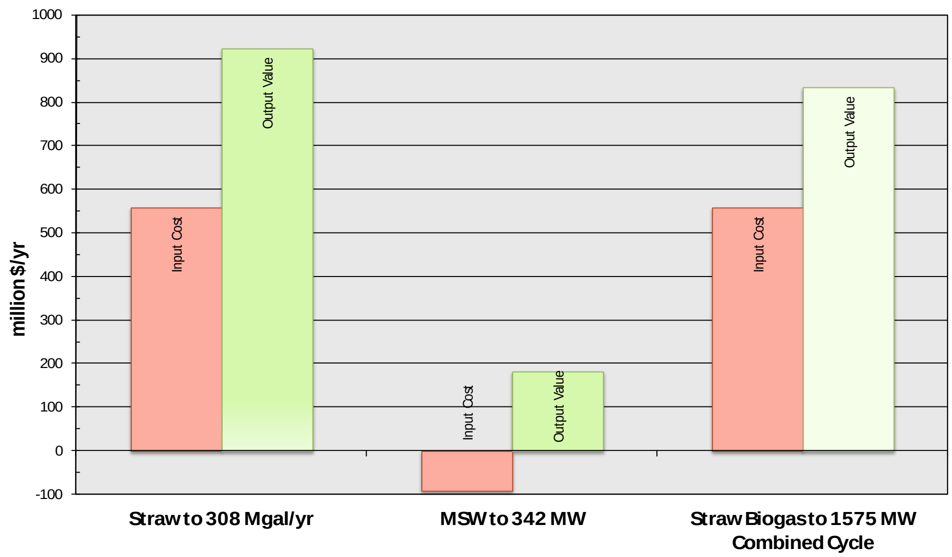

Figure 3-12. Largest Possible Plant Value Propositions.

Figure 3-13 shows the order-of-magnitude capital costs for the three power plants.

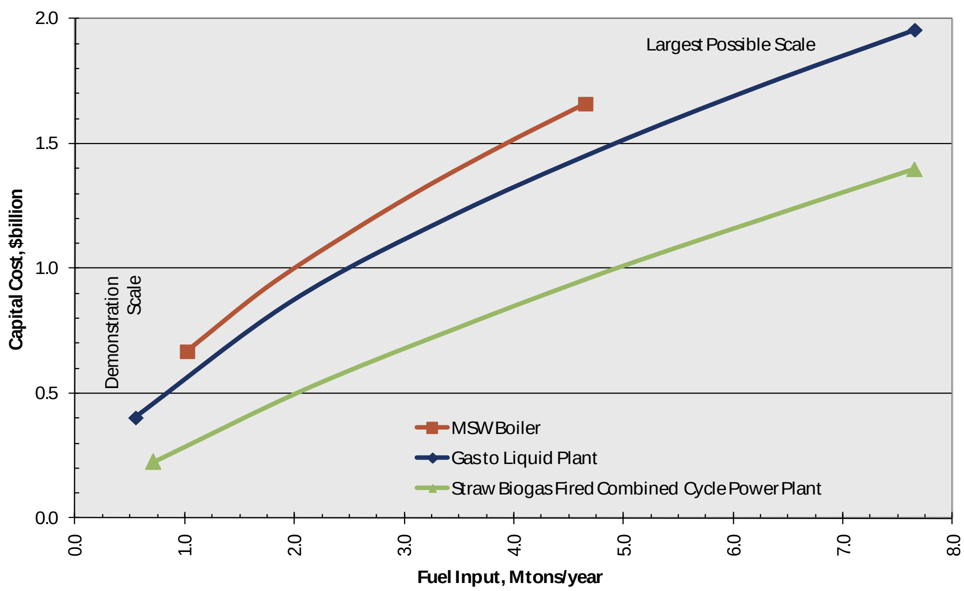

Figure 3-13. Capital Costs for Plants.

3.2.6.2 Risks

No Fischer Tropsch plant of this intermediate scale has been operated on natural gas. Larger plants, however, have operated for years on natural gas, so there are reduced technology risks. The Fischer Tropsch plant should ideally be of the low pressure type to avoid having to expend energy to compress syngas. In theory the biomass syngas may be used to power gas turbines, reformers, and produce organic liquids. In practice no one has successfully operated any of these on a sustained commercial basis using biomass syngas. The reasons for failure are not well documented but appear to be related to the tar and ash impurities. There are, however, two emerging technologies that are promising to minimize these risks. Rentech is building a demonstration plant in Sault St. Marie, Ontario, Canada, based on the Silvachem technology that operates with wood chips using hot sand. TRI Incorporated managed after a false start to operate a Fischer Tropsch pilot plant synthesis for 4 months based on biomass syngas without degradation of the catalyst and is in the process of identifying a site to build a demonstration plant.

In order to use biomass-derived syngas, it must be cleaned and under pressure using oxygen fired or indirectly heated gasifiers. Air fired gasifiers cannot be used due to the process chemistry. Syngas has to be cooled to be compressed and is difficult to compress because of its hydrogen content.

3.2.6.3 Synergies

The recently announced European Union requirement for airlines to buy carbon offsets amounts to approximately $0.24/gallon based on a current carbon credit cost of €0.22 per tonne CO_2.

As a fuel byproduct, an ash or liquid fertilizer will be produced from the mineral content of the straw containing 35 pounds of potassium oxide (K_2O) per ton of straw worth $0.47/pound to farmers[36,37] and 4 pounds of phosphorus pentoxide (P_2O_5) per ton of straw worth $0.25/pound to farmers, for a total value of $18/ton of straw which might be sold to potato farmers.[38]

Leaving straw on the fields does not contribute nitrogen to the soil. The producing wheat land has an abundance of potassium and will not require immediate replacement. Wheat farmers in the production area do not add potassium but occasionally add phosphorus. GTL plants produce steam, a little electricity, and waste heat that can be used by other processes at the site to improve project economics. A GTL plant provides a business incubator for fermentation or gasification processes to be proven at commercial scale without having to establish the path to market.

3.2.6.4 Conclusions and Recommendations

A GTL demonstration plant able to operate on any combination of straw or natural gas is one of the most promising energy investments that can be proposed in the area. To proceed, engineering studies, permitting, land and water transfers, and a market assessment that would support project development by qualified developers should be initiated. Identifying land, water, and transportation infrastructure for a plant five-to-ten times larger would increase the probability of success.

[36] "A General Guide for Crop Nutrient and Limestone Recommendations in Iowa," Iowa State University, University Extension, 2011.
[37] Daniel O'Brien and Ron Madl, *What to Consider with Cellulosic Biomass Harvest*, 2009, Kansas Wheat District Seminar presentation.
[38] Dr. N. S. Lang, Dr. R. G. Stevens, Dr. W. L. Pan, and S. Victory, *Potato Nutrient Management for Central Washington*, Washington State University, Cooperative Extension, 31.

3.3 ANAEROBIC DIGESTION OF BIOMASS TO FUELS AND CHEMICALS

3.3.1 Technology Description and Application

Anaerobic digestion (AD) is a commercially demonstrated technology capable of producing clean energy from organic wastes. It differs from other technologies in that it is capable of deployment at smaller scales and in decentralized sites, producing a methane rich biogas from crop residues. In addition to supplying clean energy, AD plants have other positive effects including the strengthening of closed loop recycling management systems, reducing emissions from the natural but uncontrolled degradation of organic residues, and producing a valuable organic soil amendment. It also can create new sources of income for farmers within the Mid-Columbia region. Figure 3-14 shows a typical AD process.

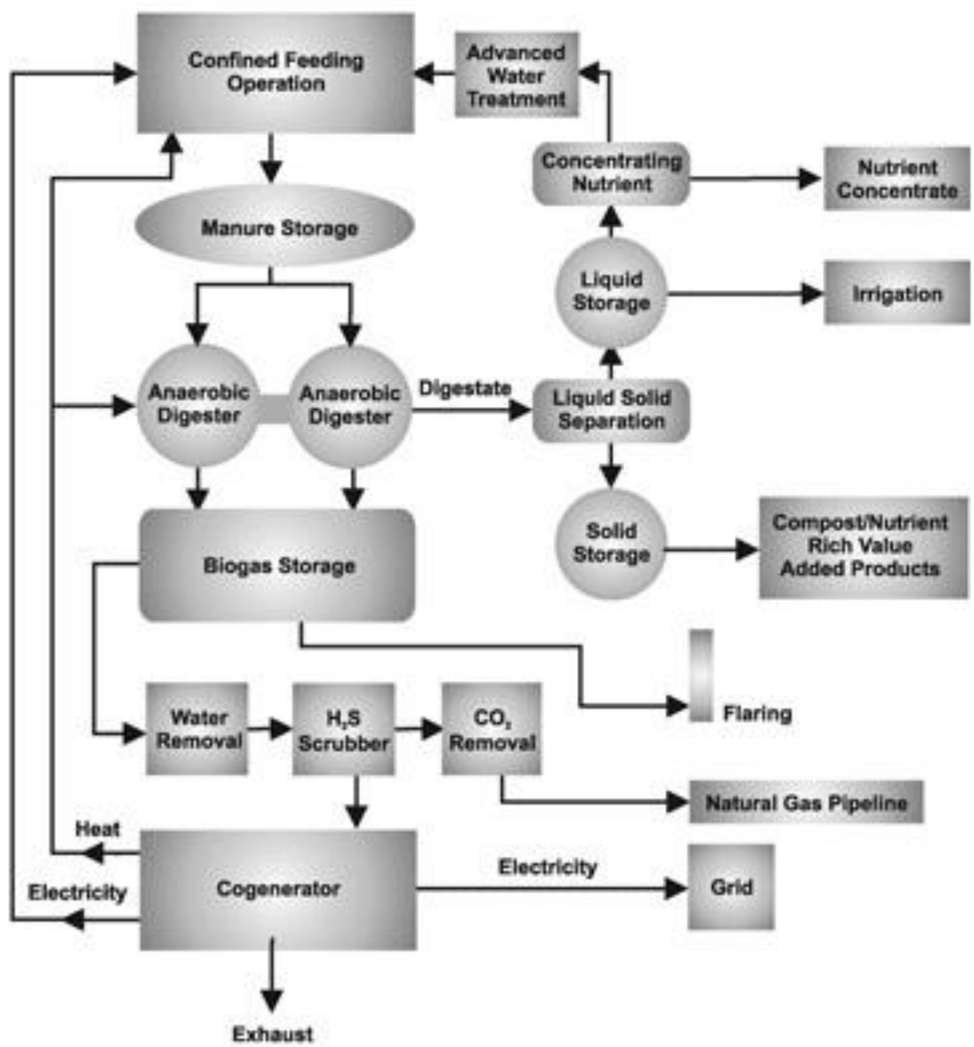

Figure 3-14. Anaerobic Flow Diagram.

Currently, less than one percent of the potential benefits from AD are being used on a national basis and no AD resources have been deployed within the Mid-Columbia region. Obstacles include the legislative framework and the lack of economic incentives for potential investors. In Europe, many countries including Austria, Denmark, England, Germany, and Sweden promote AD from organic wastes using a variety of incentives and legislative mandates. Germany leads the European Union with more than 500 operating AD plants that utilize varying percentages of biomass to increase the biogas potential.

Denmark currently has 22 large AD plants and is building one of the world's largest AD plants, Maabjerg Bioenergy, which will utilize 500,000 tons/year of mixed organics, including approximately 50,000 tons/year of non-manure agricultural biomass.

The AD process (Figure 3-15) involves the use of microorganisms and occurs in the following four steps:

1. Hydrolysis: Large polymers are broken down by enzymes.
2. Acidogenesis: Acidogenic fermentations are most important, acetate is the main end product. Volatile fatty acids are produced along with carbon dioxide and hydrogen.
3. Acetogenesis: Breakdown of volatile fatty acids to acetate and hydrogen.
4. Methanogenesis: Acetate and hydrogen are converted to methane and carbon dioxide.

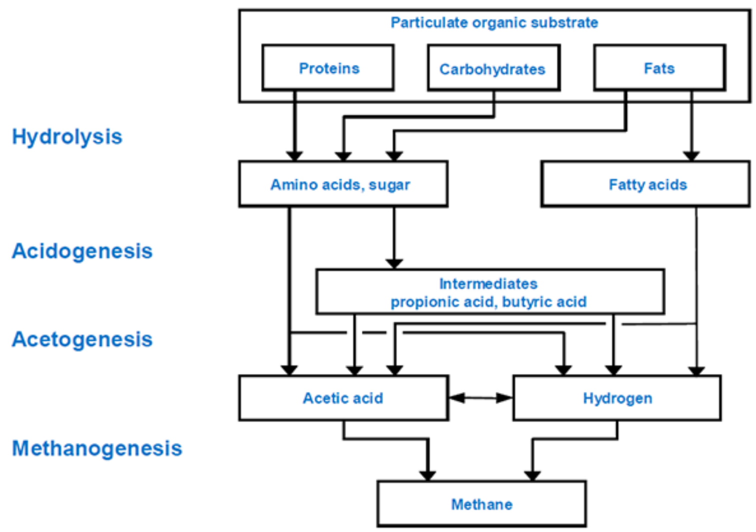

Figure 3-15. Anaerobic Digestion Process.

Two primary temperature ranges are distinguished in the AD processes:

- Mesophilic temperature from 25 - 35 °C
- Thermophilic temperature from 49 - 60 °C.

The majority of the agricultural biogas plants are operated at mesophilic temperatures. Thermophilic temperatures are applied mainly in large-scale centralized biogas plants with co-digestion where more stringent sanitation requirements are required. Usually, the produced biogas must be dried and drained to condense water and then biologically or chemically cleaned to remove H_2S, NH_3, and trace elements. Further upgrading steps to increase the CH_4 content, membrane separation of CO_2, and pressurizing the biogas can be taken depending on the utilization purpose.

3.3.2 Advanced Technologies

A relatively new alternative to traditional AD is the BioChemCat (BCC) process. BCC is a sustainable concept that allows for the phased implementation of a traditional AD process, with the sequential addition of process steps designed to recover co-products that can be upgraded to high value chemicals and fuels. The BCC process involves four major process steps: (1) pretreatment, (2) hydrolysis, (3) fermentation, and (4) catalysis. The BCC process can be implemented in a 3 phase process:

- **Phase 1** (Figure 3-16) – Develop a new AD concept where a traditional AD facility has been amended with a pretreatment facility
- **Phase 2** (Figure 3-17) – Install hydrolysis and separation equipment for recovery of intermediates, along with simple catalysis to create high value chemicals.
- **Phase 3** (Figure 3-18) – Install advanced catalysis equipment to allow upgrading of intermediates to drop-in fuels and chemicals.

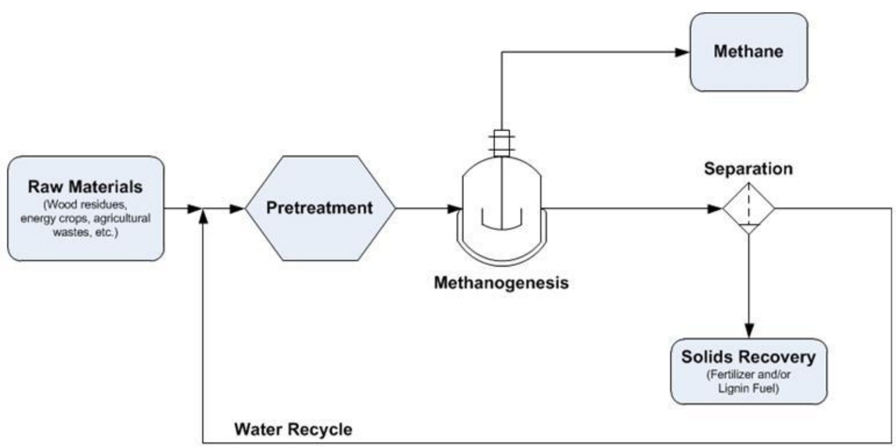

Figure 3-16. Phase 1 BioChemCat Process.

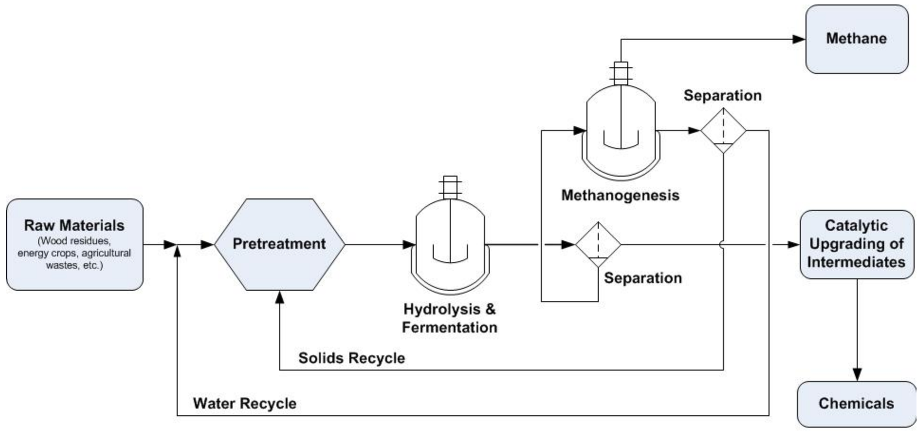

Figure 3-17. Phase 2 BioChemCat Process.

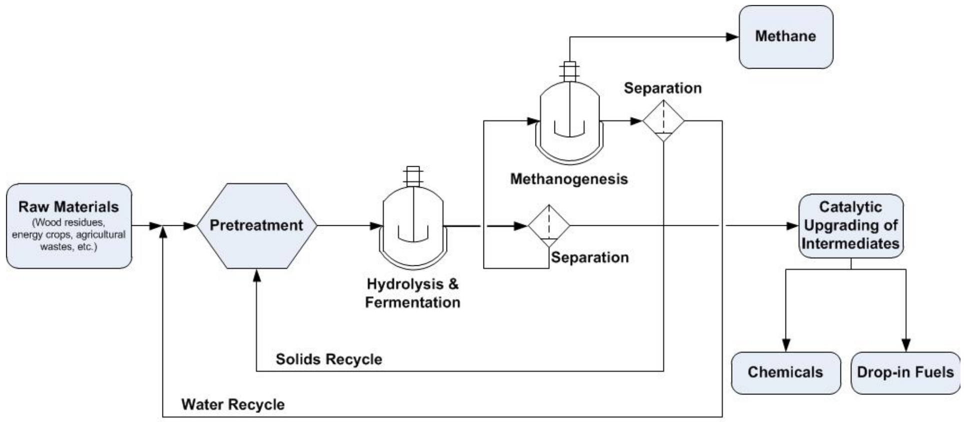

Figure 3-18. Phase 3 BioChemCat Process.

3.3.3 Pretreatment

Wet oxidation is a process where down-sized biomass material is treated under high pressure and temperature with addition of small amounts of oxygen in the form of pure oxygen, air, peroxides etc. ("Pretreatment of Wheat Straw and Conversion of Xylose and Xylan to Ethanol by Thermophilic Anaerobic Bacteria" [Ahring et al. 1996]) and includes variations of the process with steam explosion where the material is further decompressed by flashing into a flash tank ("Method for Treating Biomass and Organic Waste with the Purpose of Generating Desired Biologically Based Products" [Ahring and Munck, 2004]). As no chemicals other than oxygen are added to the process, wet oxidation will have a much lower severity and creates far less inhibitory products, such as furfural and hydroxymethylfurfural, than dilute acid and base pretreatments ("Potential Inhibitors from Wet Oxidation of Wheat Straw and Their Effect on Growth and Ethanol Production by *Thermoanaerobacter mathranii*" [Klinke et al. 2001]; "Characterization of Degradation Products from Alkaline Wet Oxidation of Wheat Straw" [Klinke et al. 2002]; "Potential Inhibitors from Wet Oxidation of Wheat Straw and Their Effect on Ethanol Production of Saccharomyces Cerevisiae: Wet Oxidation and Fermentation by Yeast" [Klinke et al. 2003]).

Under the specified conditions (170 to 190°C and up to 15 bar pressure) oxygen will react with the lignin in the biomass material resulting in de-polymerization and liberation of the hemicellulose fraction as monomeric and oligomeric sugars. Experiments in both laboratory and pilot scale have shown that enzymatic hydrolysis and fermentation can occur with a high rate at high solid material ("Enzymatic Hydrolysis and Ethanol Fermentation of High Dry Matter Wet-Exploded Wheat Straw at Low Enzyme Loading" [Georgieva et al. 2008]). The wet oxidation method has been tested on a variety of different biomass materials with high convertibility of the resulting hydrolysate when exposed to enzymes. An extended pilot study of this pretreatment was done at the Maxifuels pilot plant at the Technical University of Denmark for producing cellulosic ethanol with mixed straw as the raw material. The pretreatment process has further been tested in demonstration scale and design for industrial scale reactors.

Wet oxidation has been shown to provide very good pretreatment of any lignocellulosic material tested, including woody materials, which have proven to be difficult to pretreat by many conventional methods such as dilute acid pretreatment. The use of wet oxidation has been studied intensively for enhancing biogas production from different materials ("Wet Explosion of Wheat Straw and Codigestion with Swine Manure: Effect on the Methane Productivity" [Wang et al. 2009]). These studies clearly show how major fractions of the lignin component of the biomass are made accessible for bioconversion after pretreatment. Another recent study further showed that specific lignin degradation products are converted in the AD process ("Anaerobic Digestion as Final Step of a Cellulosic Ethanol Biorefinery: Biogas Production from Fermentation Effluent in a UASB Reactor-Pilot-Scale Results" [Uellendahl and Ahring, 2010]).

3.3.4 Hydrolysis and Fermentation

After wet oxidation, the pretreated biomass requires neutralization of the hydrolysate to pH 5.0 and addition of commercial enzymes, increasing the production cost by approximately $0.50/gallon. In addition to the cost of enzymes, this step normally requires separate reactor space under controlled conditions, which will further add to the capital and operational cost of the process.

The BCC process, however, uses a mixed culture fermentation that contains several enzyme producing species and the fermentation process can occur without adding any enzymes to the hydrolysate ("Thermal Wet Oxidation Improves Anaerobic Biodegradability of Raw and Digested Biowaste" [Lissens et al. 2004]). WSU has demonstrated (unpublished work) that simultaneous hydrolysis and fermentation of wet oxidation pretreated biomass into intermediate chemicals and methane increases overall yields by more than 30 percent ("Wet Oxidation Pre-Treatment of Woody Yard Waste: Parameter Optimization and Enzymatic Digestibility for Ethanol Production" [Lissens et al. 2004]; "Wet Oxidation Treatment of Organic Household Waste Enriched with Wheat Straw for simultaneous Saccharification and Fermentation Into Ethanol" [Lissens et al. 2004]; "Thermal Wet Oxidation Improves Anaerobic Biodegradability of Raw and Digested Biowaste" [Lissens et al. 2004]).

Fermentation into intermediate chemicals is done using a stable consortia operated at 65°C at pH 6.5 with 2 to 4 days retention time. The reason for choosing these operational conditions are long-term studies of the optimal conditions for hydrolysis/intermediate chemicals production with different feedstock's and waste ("Improving Anaerobic Sewage Sludge Digestion by Implementation of a Hyper-Thermophilic Pre-Hydrolysis Step" [Lu et al. 2008]; "Thermal Pre-Treatment of Primary and Secondary Sludge at 70°C Prior to Anaerobic Digestion" [Skiadas et al. 2005]). The stable consortia in the bioreactor is developed through initial inoculation with 12 thermophilic fermentative bacteria during startup of a bioreactor.

The bioreactor is normally operated under sanitary, but not sterile, conditions and during the startup phase changes will occur in the composition of microbes in the reactor reflecting the actual composition of the hydrolysate. In this way a stable culture is developed suitable for fermenting the different organic materials found in the hydrolysate, both of polymeric and monomeric nature, into fermentation products: intermediate chemicals (the desired product); hydrogen; and carbon dioxide. Generally the conversion of agricultural residues into intermediate chemicals yields 0.4 to 0.65 g/g-TS of pretreated material, and WSU has obtained yields of approximately 0.4 to 0.5 g/g-TS using woody materials such as Loblolly Pine and willow. During fermentation, approximately 20 percent of carbon in the raw material will end up as carbon dioxide.

The yields of intermediate chemicals per unit of organic material converted clearly shows that not only sugars are converted into soluble products in the BCC process, but that a significant portion of the lignin is also solubilized and fermented. These results are in accordance with experiments done in both laboratory and pilot scale, which demonstrated that that low molecular lignin compounds in the hydrolysate after ethanol production will be converted into methane in a biogas process ("Purification of Bioethanol Effluent in an UASB Reactor System with Simultaneous Biogas Formation" [Torry-Smith et al. 2003]; "Anaerobic Digestion as Final Step of a Cellulosic Ethanol Biorefinery: Biogas Production from Fermentation Effluent in a UASB Reactor-Pilot-Scale Results" [Uellendahl and Ahring, 2010]; "Perspectives for Anaerobic Digestion" [Ahring 2003]; "Effects on Anaerobic Biodegradability from Thermo-Chemical Pre-Treatment of Solid Manure Fractions" [Moller et al. 2005]; "Energy Balance and Cost-Benefit Analysis of Biogas Production from Perennial Energy Crops Pretreated by Wet Oxidation" [Uellendahl et al. 2008]; "Hydrolysis of Miscanthus for Bioethanol Production Using Dilute Acid Presoaking Combined with Wet Explosion Pre-Treatment and Enzymatic Treatment" [Sorensen et al. 2008]; Energy Balance and Cost-Benefit Analysis of Biogas Production from Perennial Energy Crops Pretreated by Wet Oxidation" [Uellendahl et al. 2008]).

In the BCC process, the fermentation reactor is normally operated in a continuous mode at a high constant organic loading corresponding of up to 50 kg TS/m^3 reactor volume per day. To improve production and ensure the reactor remains balanced, the intermediate chemicals are removed along with a fraction of the process water. This is accomplished using a fast rotating spinning filter mounted in the bioreactor. The BCC process employs a real-time monitoring technology ("A New VFA Sensor Technique for Anaerobic Reactor Systems" [Pind et al. 2003]; "Assembly for Withdrawing and Filtering Partial Volumes of Process Fluid" [Pind and Ahring, 2007]) that has been adapted to use for continuous liquid separation of intermediate chemicals produced by this process. Intermediate chemicals from the process water are separated out and recovered using two membranes in series. Final water removal is done using standard evaporation technology to yield a concentrated stream of intermediate chemicals containing approximately 90 percent product.

3.3.5 Catalysis

The BCC process uses catalysis of intermediate chemicals into either valuable chemicals, or using more advanced catalysis, into diesel/jet fuel precursors. Catalytic conversion of the chemical intermediates can be accomplished using several conversion pathways. The simplest is catalytic hydrogenation to mixed alcohols. This reaction is feasible with practical catalysts at temperatures in the range of 180°C to 250°C using predominantly Ru on carbon based catalysts. A variety of "promoters" have been claimed (e.g., Re, Sn, Ag, Pd, Pt, Cu, and a few others). Co or Ni + Re on carbon catalysts with optional promoters may be used and olefin byproducts can arise from dehydration. Similarly, ester and/or ether can result from the obvious reactions.

Conversion of the chemical intermediates to alcohol via hydrogenation requires considerably more sever conditions than hydrogenation of esters, but may be done in the presence of liquid water. Ester hydrogenation is a commercial process available from Davy and is normally a vapor phase process done without water present. Hydrogenation of esters normally yields two moles of alcohol unless the catalyst is unusually acidic or the resulting alcohol is especially prone to dehydration to olefin.

Conversion of the chemical intermediates via hydrogenation results in tetrahydrofuran-type products being produced. Hydrogenation catalysts of this type are sensitive to deactivation by presence of S, P, various metals such as Ca, Mg, Fe, Hg, Bi, Cd, proteins, and sugars. Sulfur containing amino acids and proteins can be especially good at poisoning such catalysts. Regeneration of activity can be accomplished in some cases, but many of the common poisons have permanent effects requiring catalyst change out. Guard beds can be effective in some cases, however, poisoning normally results in some deactivation even if regeneration is possible.

If hydrogenation of the chemical intermediates yields alcohols, particularly a predominance of those C4 and shorter, then methanol-to-gasoline or olefin-to-gasoline and distillate type chemistry can convert the mixed alcohol products to gasoline, diesel, and jet fuel if a ZSM-5 type zeolite is used. This technology is developed and offered commercially by Exxon-Mobile and has been reported in many guises by others. Titania and other oxides can do somewhat similar conversions of mixed alcohol streams.

If the mixed alcohol stream is dehydrated to a mixed olefin stream, then conventional HF or H_2SO_4 acid catalysis can yield a fuel range hydrocarbon (i.e., polymer gasoline or jet fuel). Similar chemistry can take place on some zeolites and since the hydrocarbon product usually contains some olefin, it may need stabilization by hydrogenation to remove the olefin to meet conventional fuel specs.

Another possibility for a conversion of the chemical intermediates to a more fuel like product is the Guerbet reaction. This can take place over a bifunctional oxide based catalyst and essentially provides a route to branched alcohols of higher molecular weight than the starting alcohol. The usual Guerbet catalyst is a basic oxide which also contains a hydrogen transfer component; hence the catalyst is bi-functional. Higher MW Guerbet condensation products of lower MW alcohols can be dehydrated and subjected to either acid catalyzed MW increase (polymerization to diesel and jet fuel range product) or simply hydrogenated to a pure hydrocarbon fuel.

Another pathway for conversion of the chemical intermediate product stream is catalytic dimerization. In this concept, the chemical intermediates are contacted in absence of H_2 with an oxide catalyst to yield ketone. This can be viewed as decarboxylation with dimerization, yielding a ketone (usually unsymmetrical) and CO_2, plus water. A wide variety of metal oxide catalysts have been studied and claimed in patents for this reaction which is advertised as one of the key steps in the MIXALCO[39] (TAMU-(Holtzapple) process. In the MIXALCO scheme, a stream obtained from fermentation is catalytically decarboxylated to ketone, which is then hydrogenated to a secondary alcohol.

Presumably this path may be chosen for several reasons: (1) the initial catalytic conversion to ketone might be relatively immune to poisons present in the chemical intermediates derived from the fermentation, (2) a higher MW and thus higher Btu/gallon fuel should result, and (3) hydrogenation of the ketone should be considerably less difficult than hydrogenation of the chemical intermediates to alcohols. As with other mixed alcohol streams, any alcohols derived from hydrogenation of ketone product can be dehydrated and hydrogenated to a non-oxygenated hydrocarbon fuel.

[39]MIXALCO is a registered trademark of Terrabon, LLC, Bryan, Texas. MIXALCO is an advanced bio-refining technology that converts low-cost, readily available, non-food, non-sterile biomass into valuable chemicals such as acetic acid, ketones and alcohols that can be processed into renewable gasoline fuels.

3.3.6 Engineering and Economic Evaluation

A preliminary techno-economic model of AD of biomass, primarily straw, that is produced in large quantities throughout the region was developed by CleanVantage based on the degradation of biomass to produce biogas using the AD and BCC process configurations. The prices of co-products may vary considerably and, therefore, sensitivity analyses should be performed to evaluate the effects of these variations on the overall system costs. Summary comparative cost results are presented in Table 3-2. Estimated capital equipment and operating costs are presented in Table 3-3.

3.3.7 Risks

As a mature technology, AD technology has been demonstrated to be competitive on a cost per Btu basis with other combustion technologies. BCC lacks a demonstration of its capability at the present time. The risks for each stage of AD and BCC development are summarized in Table 3-4. The perceived technological risk of the proposed project is low to moderate.

3.3.8 Conclusions

AD is a commercially demonstrated technology capable of converting biomass into useful chemicals and fuels, and can be implemented in a phased manner to be cost competitive with natural gas on the commercial market. The BCC technology, which is fully compatible with AD, is highly promising and both technologies, separately and together, should be further evaluated for potential use. The BCC technology is still maturing and its capability can be effectively demonstrated at scale using a phased project completion approach.

Table 3-2. Comparative Cost[40] of Energy.

Manure AD Systems by Species	Unit of Measure	Cost per Unit ($)	Btu per Unit	$ per M Btu	$ per Therm	$ per Giga Joule
AD Covered Lagoon - Swine	1,000 ft^3	1.90	600,000	3.17	0.32	2.99
AD Covered Lagoon - Dairy	1,000 ft^3	2.40	600,000	4.00	0.40	3.77
AD Mixed - Dairy	1,000 ft^3	2.60	600,000	4.33	0.43	4.09
AD Mixed – Other swine	1,000 ft^3	3.52	600,000	5.87	0.59	5.53
AD Plug Flow	1,000 ft^3	4.33	600,000	7.22	0.72	6.81
Natural Gas	**1,000 ft^3**	**9.68**	**1,030,000**	**9.40**	**0.94**	**8.87**
AD Mixed – Other	1,000 ft^3	6.97	600,000	11.62	1.16	10.96
Jet Fuel	Gallon	2.235	128,100	17.45	1.74	16.46
Propane	Gallon	1.571	91,300	17.21	1.72	16.23
Diesel Fuel	Gallon	3.098	129,500	23.92	2.39	22.57
Heating Oil	Gallon	3.098	129,000	24.02	2.40	22.66
Gasoline	Gallon	2.847	114,500	24.86	2.49	23.46

[40] Costs are based on 2010 US Energy Information Agency data.

Table 3-3. Estimated Capital and Operating Costs for a Project Based on 50 Million Gallons per Year Plant and Input Biomass Costs of $60 per Ton.

Equipment Costs (2007 $) (Biochemical)	Installed Capital Cost (MM$)*		
	Phase 1 Biogas Only	Phase 2 Biogas & Chemicals	Phase 3 Biogas, Fuels & Chemicals
Feedstock Handling	6.00	6.00	5.00
Pretreatment	40.00	0.00	40.00
Separation of Intermediate Chemicals and Lignin	0.00	71.00	71.00
Fermentation Organism Production	0.00	66.00	66.00
Biogas	22.00	22.00	22.00
Catalytic Conversion and Product Recovery	0.00	75.50	90.00
Wastewater Treatment	40.00	40.00	40.00
Storage	5.00	15.00	15.00
Civil Infrastructure (buildings; heating, ventilation, and air conditioning, etc.)	10.00	24.00	26.00
Utilities (include steam/electricity)	12.00	40.00	46.00
Line 2: Total Installed Capital	**135.00**	**399.50**	**421.00**
Total Installed Capital Costs ($/Gal Equivalent)	**2.70**	**7.99**	**8.42**
Operating Costs (2007 $)	**MM$/yr**	**MM$/yr**	**MM$/yr**
Feedstock	40.00	40.00	40.00
Organism Production Nutrients	1.50	2.50	2.50
Separation System (membranes, etc.)	0.00	28.00	28.00
Conversion Catalyst	0.00	28.00	55.00
Other Raw Materials	1.25	1.25	1.25
Waste Disposal	5.00	5.00	5.00
Steam[2]	0.00	2.00	2.00
Electricity	5.50	19.50	20.50
Labor and Maintenance	7.50	25.00	26.50
Total Operating Costs	60.75	151.25	180.75
Co-product Credits	0.00	11.00	15.00
Net Operating Costs	**60.75**	**140.25**	**165.75**
Net Fuel Production Costs ($/Gal Equivalent)	**1.215**	**2.805**	**3.315**

Table 3-4. Key Technical Risks and Mitigation Strategies. (2 pages)

Task/Process Step	Barriers	Risk Level	Risk Mitigation
Biomass (agricultural residues) supply for later up-scaling with a maximum cost of $60 per dry ton	Inadequate quantity available within 50 miles of satellite processing facilities	Low	Nearly 2.5 million tons available in local region; spoke/hub model allows biomass processing at satellite facilities and centralized processing only of concentrated intermediate chemicals.
Biomass pretreatment	None – established technology	Low	None required.
Fermentation of hydrolysate to intermediate chemicals	Inhibitory compounds are produced during pretreatment inhibiting the fermentation process	Low	None required. Fermentation of different hydrolysate into intermediate chemicals has been tested on several types of hydrolysate with good performance.
Intermediate chemicals recovery	Filter and membrane costs, recovery efficiency	Moderate	Filter unit in reactor plugs: Risk mitigation is cross flow filtration outside reactor. Membrane problems: Back-up solution is the evaporative distillation of the liquid stream from the reactor.
Conversion of intermediate chemicals to fuels	Cost/effect of catalysts	Moderate	Variety of catalysts have already been tested, main focus on optimization and cost reduction.
Partly conversion of lignin in addition of carbohydrates into intermediate chemicals	Pretreatment fails to depolymerize lignin	Low	Extended research has demonstrated lignin removal of pretreated material during anaerobic digestion.
System inflexibility for variations in woody biomass composition	Woody residues, such as hog fuel and thinnings, will vary significantly in composition	Moderate	Better upfront mixing of preprocessed biomass raw materials and better management to ensure slow changes in nature of materials.
Problems meeting the targeted fuel prices	Catalyst cost higher than predicted	Moderate	Only low cost catalysts will be tested to ensure that the estimated upgrading cost will be met.

3.4 MUNICIPAL SOLID WASTE-TO-ENERGY

Municipal Solid Waste Summary

- Improved WTE technology compared to incinerators has entered the marketplace, yielding far better pollution controls and efficiency.
- Pryolysis and gasification processes provide feedback from MSW for GTL plants.
- Robust supply chain in the United States for gasification and other techniques.

Waste-to-Energy & Electricity from Waste – Waste-to-Energy (WTE) takes several forms. One commonly known form is landfill gas, where methane is extracted from landfills, cleaned, and burned in a gas turbine or an IC engine to create electricity. A second form is “mass burn” or incineration. The basic “mass burn” technologies fall into two groups: traditional stoker boilers and gasifiers. Incinerators simply burn the waste and use the heat to create steam and expand that steam through a steam turbine to create electricity, sometimes using excess heat in a cogeneration process. With respect to combustion technologies, there has been concern in the past with the production of air pollutants from various contaminants in the MSW. There were two basic approaches to addressing those contaminants in the past. One is to burn the entire feedstock using a plasma arc. This method is costly and uses as much electricity as it produces. The other is to separate materials before and after combustion to eliminate the pollutants. Based on the recent permitting of a MSW facility in Florida, organizations can meet air quality standards with current technologies. The basic combustion technologies fall into two basic groups: traditional stoker boilers and gasifiers.

When used with MSW, AD is a newer process that isolates the organic components of MSW and allows them to be reacted by bacteria to create methane directly rather than waiting for the process to occur naturally in the landfill. The benefits of this process are that it minimizes fugitive methane from the landfill and the gas is cleaner and easier to manage. The downside is that it requires a finer degree of waste stream pre-processing than is typical in the industry to avoid affecting the process by introducing contaminants. The organic material from MSW comes in several forms and various levels of containments. The moisture content is a major factor in determining the method of separation and the process that is best suited for extraction of value from the waste. MSW with more than 60 percent moisture needs to be dried first using waste heat or used in a fermentation process such as AD to break down the waste.

When selecting the anaerobic path, the waste is converted to biogas that is approximately 52 percent methane and 48 percent carbon dioxide, which is created by bacteria in oxygen depleted environment. This methane could be upgraded into traditional fuels or other products or burned directly in a gas turbine or IC engine. The cleaning required is largely dependent on the amount of secondary elements that need to be removed at some level for the biogas to be used effectively in the generation of electricity burning in an IC engine or turbine, or in the development of other products.

The secondary elements include moisture, sulfur in the form of hydrogen sulfide, ammonia, and siloxanes. Moisture needs to be removed to promote complete combustion and can easily be removed by cooling the intermediate stage of the reaction so that the moisture is condensed and then reheating the reaction products after draining the moisture. Sulfides need to be removed to prevent sulfuric acid generation, which is detrimental to the gas cleaning, heat recovery, and exhaust portions of the engines. Typically this can be done biologically or chemically through well established processes down to below the 200 ppm minimum level required by most engine manufacturers. Ammonia also will not be completely combusted in typical engine design and will create corrosive gasses and liquids when burned. Ammonia is easily removed with the injection of acid and/or a water mist spray. Siloxanes are the most difficult to remove; however, suppliers are available that sell equipment to remove siloxanes, but it is very expensive. Depending on the level of siloxanes, some owners choose not to clean the biogas and instead perform regular maintenance to clean the engines. Siloxanes condense in the engine and form a ceramic-like film on the inside of engine parts. If not cleaned, this film will cause hot spots on valve heads and cylinders, which can cause catastrophic failure or restrict air flow and increase the wear on moving parts.

More modern techniques for use of MSW include pyrolysis and gasification. In both of these approaches MSW is heated in a reduced or no oxygen environment to break the components down to hydrogen, carbon monoxide, carbon char, and other molecular fragments. A key benefit of using gasification is that, due to the reduced oxygen content, dioxin and furan generation is reduced by 98 percent compared to the older generation of incinerators, achieving levels far more stringent than current U.S. Environmental Protection Agency regulations, as shown in the Table 3-5.

The gas created by pyrolysis can be cleaned prior to being sent to the gas turbine for combustion, further enhancing the pollution control capability of a modern WTE facility. The clean gas is then burned in the gas turbine to create electricity and can be combined with a steam turbine for a combined cycle plant, or the turbine exhaust heat can be used for district heating or gasification process pre-heating needs. Alternatively, the syngas can be reformed into liquid fuels and combined with the rest of the output from the GTL plant.

Table 3-5. Sources of Dioxin/Furan Air Emissions in the United States, in Grams Toxic Equivalents (Toxics Release Inventory).*

Source	Year		
	1987	1995	2002
Waste-to-Energy Facilities	8,877	1,250	12
Coal-Fired Power Plants	51	60	60
Medical Waste Incineration	2,590	488	7
Barrel Backyard Burning	604	628	628
Total United States	13,998	3,225	1,106

*http://www.nmwda.org/news/documents/Tab3-Psomopoulosetal2009WTEstatusandbenefits2.pdf

An issue with pyrolysis and gasification processes is the tar content of the output. Tars are aromatic compounds that remain behind when the carbon chains are removed in pyrolysis. A new technique for removing tars is to scrub them using JP-8, absorbing the oil-soluble tars into the fuel, thereby allowing the remaining tars to be removed more easily. The oil-soluble tars increase the energy content of the fuel; however, the aromatics negatively impact the long-term stability of the fuel. Fuels made this way should be used locally in vehicle fleets, or for local vehicular use via wholesale distribution.

Other issues with gasification, such as slag and clumping for bubbling fluidized bed gasifiers with potassium, making the sandstone sticky and choking out the airflow. Additionally, the temperature must be tightly controlled, as temperatures that are too high or low will limit the process effectiveness. Additional equipment such as heat plates help absorb excess heat. Sand also can be replenished over time specifically targeting the sand that has clumped.

3.4.1 Value Proposition

The value proposition for a MSW plant includes tipping fees, electricity generation, and feedstock generation for a GTL or other chemical precursors. Tipping fees average $45/ton nationally, depending on local alternatives and relative scarcity of landfill space. The value of the electricity generated would be limited by the “green power” premium currently in existence in the market plus the value of the electricity itself.

3.4.2 Fuel Availability

As previously stated, MSW can be used as a fuel to generate energy and other products. The three sources of waste identified for potential use are shown in Figure 3-19. The first is MSW from cities in Western Washington, except Seattle, is sent to the Roosevelt Regional

Landfill in Eastern Klickitat County. This landfill is permitted to receive 3 million tons/year and is seeking to expand to accommodate an additional 1 million tons from the lower mainland of British Columbia. The MSW arrives in Klickitat via railroad and is trucked to the landfill site. Part or all of this waste may be available to extract energy. This rail line extends about 75 miles further to the Port of Benton and the MSW could be brought for preprocessing to extract valued byproducts from the waste prior to final disposal.

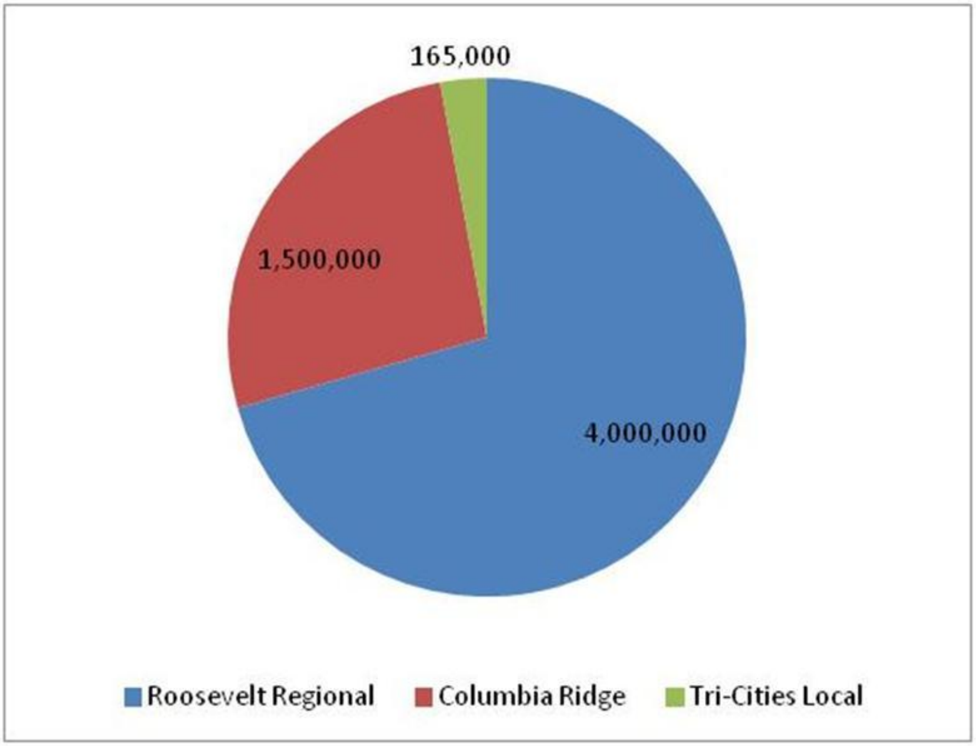

Figure 3-19. Municipal Solid Waste Availability (ton/year).

Waste Management at the Columbia Ridge Landfill in Arlington, Oregon takes about 1.5 million tons/year by train, truck, and barge (this total includes 0.4 million tons/year from Seattle). Lastly, the MSW from the Tri-Cities area could be utilized to generate value.

A typical American produces 4.5 pounds/day of MSW. For the approximately 200,000 people in the Tri-Cities area, the total MSW production is on the order of 450 tons/day, or about 160,000 tons/year. Figures from a recently permitted MSW plant in Palm Beach, Florida show that it takes 1.66 tons of MSW per net MWh generated, so the Tri-City waste could generate 99,000 MWh/year for the area. This saves approximately 69,000 tons of CO_2 from being emitted by power plants in generating the same amount of energy.[41]

3.4.3 Supply Chain

With respect to MSW combustion, there are at least three major suppliers in the United States that were identified through a recent competition to convert MSW to energy in Florida.

[41] http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

The three companies were Babcock &Wilcox (B&W), Wheelabrator, and Convanta Energy Corporation. These companies have multiple operating plants in North America. B&W won the competition through the use of a vertically integrated system that uses their own boilers and air cleaning equipment.[42] B&W achieves some of the highest efficiency because of the system's ability to handle the highest temperatures and pressures in the industry (1300 psi, 930 °F). While this range is not uncommon in clean biomass, it is notable for MSW because the corrosive materials in MSW, which keep most vendors' systems below these temperatures.

The new system in Palm Beach, Florida will consume 3,000 tons/day (approximately 1 million tons/year) of MSW and produce 75 MW of net electrical power. That is approximately 40 tons/day/MW, which compares reasonably with the 30 to 35 tons/day/MW when using green wood as the feedstock. Of particular note are the potential jobs created by such a facility as that being built in Florida. The WTE plant is scheduled for commercial operation in spring 2015.

Two issues must be discussed in the analysis of MSW-to-energy development that can affect conclusions on this subject:

- **Resource Location** - The bulk of MSW resources available for use in the Mid-Columbia region are generated in the heavily populated western areas of Washington and Oregon. Transportation costs for bringing the MSW to a processing installation in the Mid-Columbia region will be a significant factor in final cost of whatever form of energy is marketed. MSW-to-energy projects are being considered in Western Washington, which would have lower freight costs than one located in the southeastern portion of the state. In addition, the potential economics for an MSW-to-energy project are good enough that there is high likelihood of competition developing for the resource. The best location for an MSW project will most likely be near the point of generation.
- **Political Support** - The concept of moving large amounts of MSW from the large western population centers of Washington and Oregon to the Tri-Cities region would be a contentious issue for local governments and civic organizations. Such contention, while not insurmountable, will add to the difficulty of creating and sustaining a development effort. Political issues will make development of a major MSW processing facility a better fit at current disposal sites (landfills), or nearer to point of generation.

While neither of these issues rules out MSW as a resource, they make building developments around MSW more difficult. New technologies for processing biomass into energy are becoming more omnivorous, and as such, MSW can be considered as a potential supplement to agricultural waste as a resource for development. Use in a primary role is less likely to succeed.

3.4.4 Conclusions

MSW has significant potential to add to the economic redevelopment of the Tri-Cities area through inclusion of an MSW gasifier to supplement the gasified wheat straw and natural gas feedstock for a GTL plant. Rail and barge infrastructure is already in place to supplement the local MSW with intake from the Roosevelt and Columbia Ridge landfills.

Although the economics and technical aspects of MSW processing for energy are appealing, economic and political considerations make MSW a less desirable resource than other sources

[42]Details on the new Palm Beach, Florida, facility can be found at http://www.babcock.com/library/pdf/sp-585.pdf.

generated within the region. Consideration of MSW as a supplement to other biomass sources is reasonable, but is not considered an optimum path.

3.5 SOLAR

3.5.1 Photovoltaic

Deployment of PV systems has increased over the past several years and has realized cost reductions that make investment in the technology more attractive than in the past. The cost of PV panels has fallen near $1.50/W, the output of individual PV panels has increased, and the modularity of this type of technology has helped deployment at residential, commercial, and utility scales. PV deployment can be very distributed. Small-scale PV systems (1 MW AC) may be deployed in such a manner as to avoid impacts on the regional electric grid, and for new construction, building integrated photovoltaic (BIPV) approaches may be considered. For various reasons, deployment of PV systems in the Mid-Columbia region would be an opportunity to provide green economic advantages, and presents attractive potential to capture the available solar energy resource.

Solar Photovoltaic Summary

- PV deployment has gained cost effectiveness due to capital cost reductions. Projects should now be financially viable.
- PV deployment has increased over the past several years as the technology has matured with better economics.
- Since PV/solar electric is extremely modular in nature, multiple projects or multiple phase projects may be used to expand renewable power generation deployment over time.
- State and federal incentives to deploy PV are evolving.
- To accelerate the deployment of cost-effective solar energy generation, a strategy similar to DOD's NZEI may be considered.

The purpose of this section is to characterize opportunities for the utilization of PV systems in the region, and to assess changes since the Federal Energy Management Program (FEMP) *Transformational Energy Action Management PV, CSP, and Biomass Feasibility Assessment Final Report* (Dean and Haase, 2008) (FEMP Report) was published.

3.5.1.1 Photovoltaic Solar Electric Technology Application

Solar electric (PV) is highly synergistic with other forms of clean energy generation. For example, use of PV may defray the costs of concentrated solar power (CSP) generation parasitics; however, the ideal deployment of PV occurs at remotes sites where the use of diesel generators may be reduced. In this case, there is cost avoidance based on the cost of diesel fuel and emission reductions. PV is synergistic at the grid level and below and is different than CSP methods where solar thermal energy may be used in conjunction with gas or steam turbine power generation. Deployment scales are characterized in Figure 3-20.

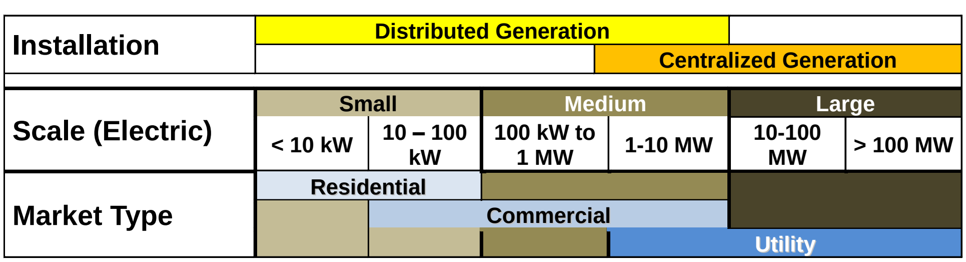

Figure 3-20. Decentralized and Centralized Deployment and Scales.

The overall objective of solar energy generation is to maximize investment and minimize cost without impacting the existing electric grid. Without expensive power and energy storage systems, the intermittent nature of PV production impacts grid stability. Obviously, centralized and large-scale PV deployments require more land and larger grid interconnections, making proximity to the grid tie very important to avoid the need for additional transmission lines. More distributed and small-scale "customer sited" PV projects generally take less time to deploy, require smaller tracts of land, are closer to the load, and will have less grid impact. Therefore, it is highly recommended to investigate feasibility of PV deployment at all scales.

Based on efficiencies alone, it does not make sense to use PV to generate steam to meet process loads (Figure 3-21) because CSP thermal is four times more efficient than PV for steam generation.

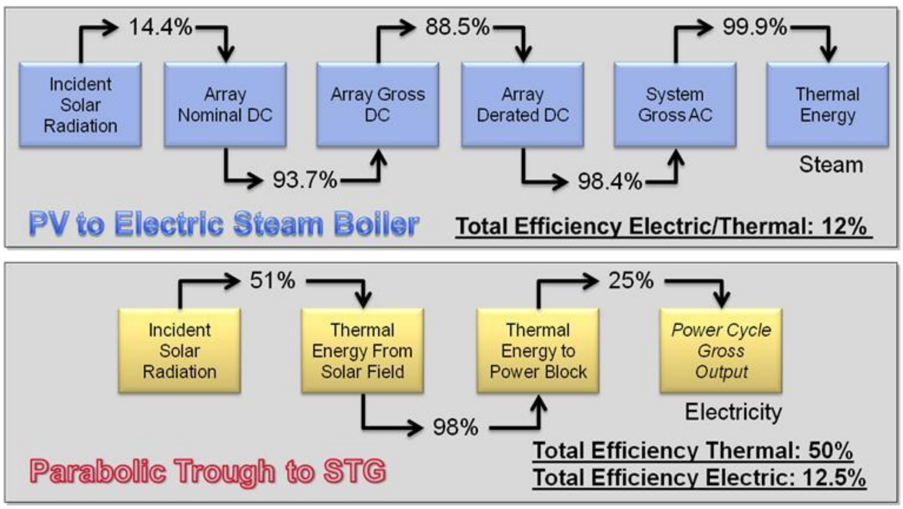

Figure 3-21. End to End Efficiency for Steam Comparison of Photovoltaic versus Parabolic Trough (CSP).

Based on the cost of PV alone, CSP should not be used for small-scale power generation (10 MW), for new construction, or new CHP applications. The level of PV deployment has surpassed the level of solar thermal deployment based on cost and ease of integration.

Because PV power production is often closely aligned with peak load periods, PV can be used to effectively level the peak by handling air conditioning load demands during the summer months. For this application, it is recommended to consider PV to support the energy demands of the industrial park, where rooftop mounted PV or elevated structure PV may be deployed, maximizing the use of available acreage. Based on the recent increased deployment of this form of technology, this type of deployment has become common practice.

Hybrid systems combine thermal and electric generation at a small (customer sited) scale. Cogenra Solar is one such supplier that uses a parabolic trough to generate both electricity (via PV) and hot water for sanitation use. This would be a distributed deployment near buildings.

3.5.1.2 Region-Specific Feasibility Assessment

Based on the available land and grid interconnections, the Mid-Columbia region provides an attractive opportunity for PV development to enhance economic development for the following reasons:

- PV generation projects sometimes require upgrades to transmission lines due to access required at remote site locations (i.e., away from the load); however, there are adequate substations for grid interconnections in the region to make interconnection a low-priority issue. Transmission line capacity should not be an issue, as loads at decommissioned sites no longer exist, and there is adequate room for these lines to transmit PV power on the BPA grid; however, interconnection location and line capacity must be coordinated with the existing utility system.
- PV systems may be located on existing building rooftops, provided that structural load analyses are performed. Small ground-mounted systems may be erected nearby if rooftops are not viable.
- PV systems could be provided on any new construction in the region, either on rooftops, as BIPV, or on elevated structures providing electric vehicle charging, as has already been installed at PNNL.

3.5.1.3 Engineering and Economic Evaluation

PV systems support rapid deployment, can attract financing, and have a history of operational data to improve investment and bankability. The number of PV component suppliers and constructors has increased as the supply chain is maturing. Project assessment tools also have matured and multiple performance monitoring systems have become available on the market. Competitive PV product development has produced improved PV modules (panels), balance of system components (racks, trackers and wiring), power electronics (centralized inverters and micro inverters), and construction techniques over the past several years.

Sample calculations for analysis purposes were computed for a notional site located on DOE land at Lat 46 degrees 21 minutes North, Long 119 degrees 15 minutes West. This site was selected to be able to use an excellent source of meteorological data available, because it would provide representative results for the region, and to provide a basis to compare to previous reports. This information was downloaded from National Renewable Energy Laboratory (NREL) Solar Prospector, using file radwx_119254635.tm2. Based on the composite weather file, the annual average direct normal insolation (DNI) is 206.8 Wh/m^2 (Figure 3-22), and the average diffuse horizontal radiation is 61.1 Wh/m^2 (Figure 3-23).

The available insolation (Figure 3-24) indicates that, with this sizable diffuse component, concentrating PV systems (two axis tracking with a lens or mirror concentrating device) would not be ideal for the region, though one axis tracking to better produce power in the winter months would be attractive.

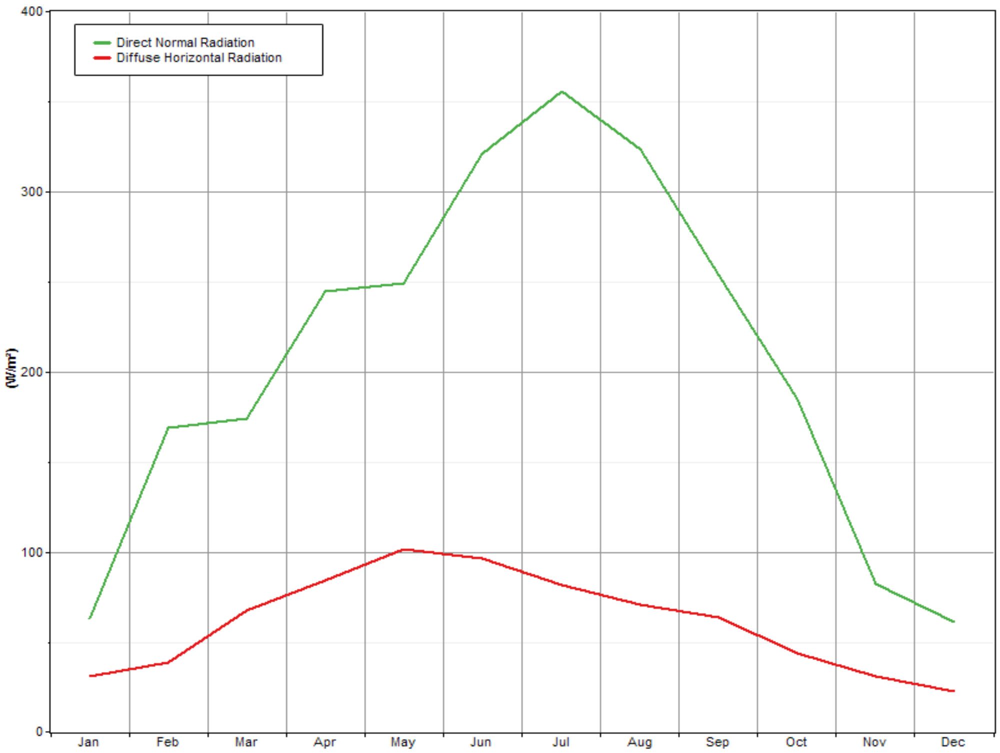

Figure 3-22. Available Solar Resources - *Average DNI and Diffuse by Month*.

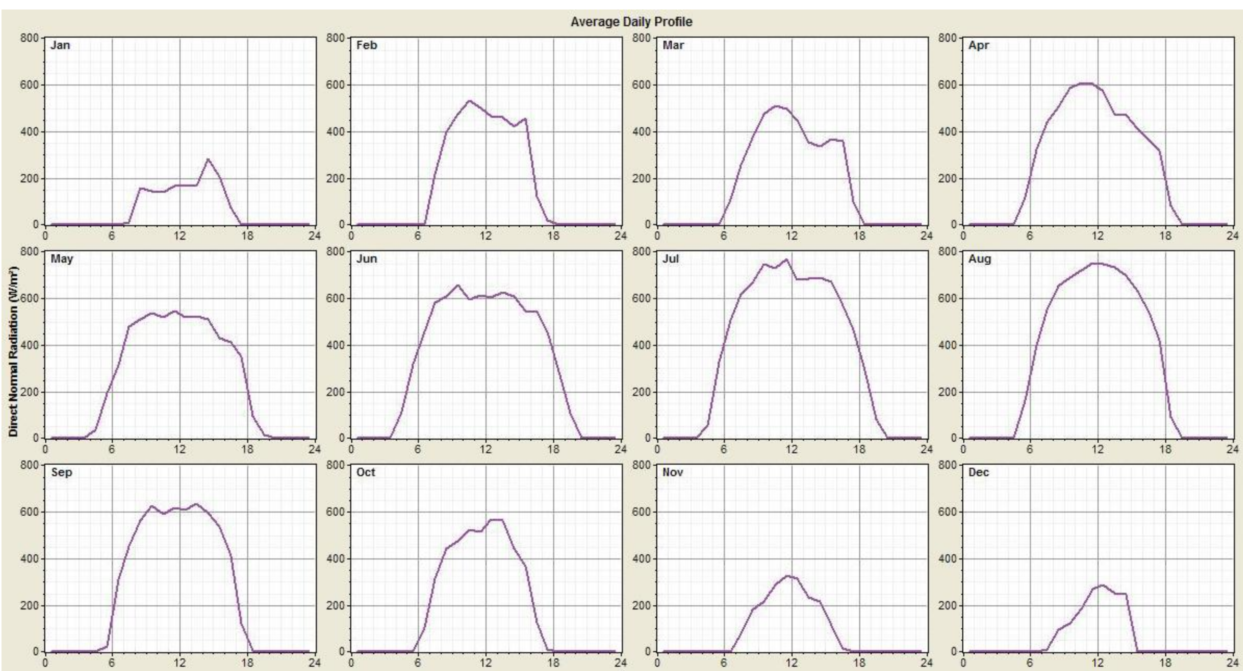

Figure 3-23. Available Solar Resources - *Monthly Profile of DNI*.

Figure 3-24. 300 Area and Insolation Data Grid Location.

As previously mentioned, the technical or engineering parameters used to assess the feasibility of PV system deployment should be updated based on known improvements. To assess the impact of technology improvements, a 5 MW AC ground-mounted system was modeled using PVSyst. The inputs and results of the comparison are shown in Table 3-6.

Table 3-6. Engineering Reassessment (Comparison).

Federal Energy Management Program Report	**New Evaluation**
Array Characteristics • Efficiency 13.47 percent • Pmp 175 Watts • Module Area 1.3 m^2 • Isc 5.388 Amps • Voc 45.5 Volts • Imp 4.87 Amps • Vmp 35.95 Volts	Array Characteristics • Efficiency 14.58 percent • Pmp 282 Watts • Module Area 1.94 m^2 • Isc 8.330 Amps • Voc 44.80 Volts • Imp 7.95 Amps • Vmp 35.20 Volts
10 Modules/String, 2,870 Strings in Parallel	17 Modules/String, 1,208 Strings in Parallel
10 total 500 kilowatt (kW) Inverters, Efficiency 92 percent	20 total 250 kW Inverters, Efficiency 96.9 percent
First Year Output: 8,618,869 kilowatt hour (kWh)	First Year Output: 8,464,000 kWh
	Output File (see Appendix B)
	Total Module area = 39,847 m^2 (9.85 acres)

Since all module and array related input parameters used for the initial report were not known, it was difficult to match original input assumptions for production simulation. The 2 percent difference between the first year system energy production outputs could be accounted for by differences in the input assumptions along with variations in weather data used for the modeling. However, the new system configuration was intentionally not the same, a larger PV panel and smaller inverters were used for the reassessment to indicate potential performance improvements using improved system components. For example, the reduced number of PV strings requires fewer combiner boxes. To determine the tracking benefits, the PV system was modeled on a fixed 38 degree tilt and had a first year output production of 7,226 MWh, which was 85 percent of the 1 axis tracking estimate of 8,464 MWh.

The intermittent nature of solar electric technology upon the grid could be mitigated to some extent by the deployment of power and energy storage systems. There have been deployments of large-scale storage grid-connected projects funded by the DOE and other agencies. Short duration power storage technologies include Ni-Cad, Dry Cell, or Li-Ion battery systems. These systems provide ancillary services. Long-term energy storage systems include flow-batteries, providing peak shaving. Deployment project-sited storage systems add to capital expenses and require the solar generation capacity to be larger (more PV modules) to support charging these systems.

From the economic standpoint, it is obvious that a power purchase agreement (PPA) is required to make any large-scale PV project viable; without the Investment Tax Credit (ITC) or Cash Grant, a large project would probably not be financially viable.

Rates have not changed since the FEMP study, and 31 cents/kWh is roughly equivalent to the present rate. As previously stated, the "average" non-slice Priority Firm rate for power in Fiscal Year (FY) 2011 is about $27/MWh; correspondingly, the "average" transmission service rate is about $3/MWh. However, the economic assessment of PV should consider the findings of recent trends documented by a September 2011 Report from Lawrence Berkley National Laboratory:

- The installed cost of utility-sector systems varies significantly across projects. Among the 20 utility-sector projects in the data sample completed in 2010, installed costs ranged from $2.9/watt (W) to $7.4/W, reflecting the wide variation in project size (from less than 1 MW to 34 MW), differences in system configurations (e.g., fixed-tilt versus tracking and thin-film versus crystalline modules), and the unique characteristics of individual projects.
- Current cost benchmarks for utility-sector PV are generally at the low-end of the range exhibited by the 2010 projects in the data sample, with various entities estimating an installed cost of $3.8/W to $4.4/W, depending on system size and configuration for utility sector systems installed at the end of 2010 or beginning of 2011.
- The installed cost range of utility-sector systems in the data sample declines with system size, consistent with expected economies of scale. For example, among fixed-tilt, crystalline systems installed over the 2008 to 2010 period (a broader range of years is included in order to increase the sample size), costs ranged from $3.7 to $5.6/W for the five 5 to 20 MW systems, compared to $4.7 to $6.3/W for the three <1 MW systems. Similarly, among thin film systems, the installed cost of the two >20 MW projects completed in 2008 to 2010 ranged from $2.4 to $2.9/W, compared to $4.4 to $5.1/W for the two <1 MW projects.

- Installed costs are lowest for thin-film systems and highest for crystalline systems with tracking. Among >5 MW systems installed from 2008 to 2010 (a broader range of years is included in order to increase the sample size), installed costs ranged from $2.4 to $3.9/W for the five thin-film systems, compared to $3.7 to $5.6/W for the five crystalline systems without tracking and $4.2 to $6.2/W for the four crystalline systems with tracking. To more comprehensively compare the cost of these alternate system configurations, one would need to also consider differences in performance and the related impact on the LCOE.[43]

Figure 3-25 shows the differences between technologies (thin film/crystalline, fixed/tracked). Considerations/tradeoffs made between these various approaches still exist (tracked system still provide 20 percent more production than fixed systems) and should be considered on a project by project basis using bottoms up pricing based on a preliminary design.

These installed costs are considerably lower than values in Table 6 of the FEMP Report and the installed costs used in the economic analysis. The total installed costs used in Cases 1-3 in the FEMP Report can now be reduced accordingly. For example, the total installed cost of the first two cases was $32,099,535 for 5,000 kW AC, equaling $6.42/W. New information on the average cost per watt installed, approximately $5.50/W, results in a 14 percent reduction (revised total installed cost of $25.5 million). Table 3-7 shows the revised average cost data.

Despite improved modules, balance-of-system equipment, and inverters, any operations and maintenance (O&M) decrease since 2008 is most likely offset by labor rate increases; therefore, this LCOE component is not expected to change to a significant degree since the 2008 analysis.

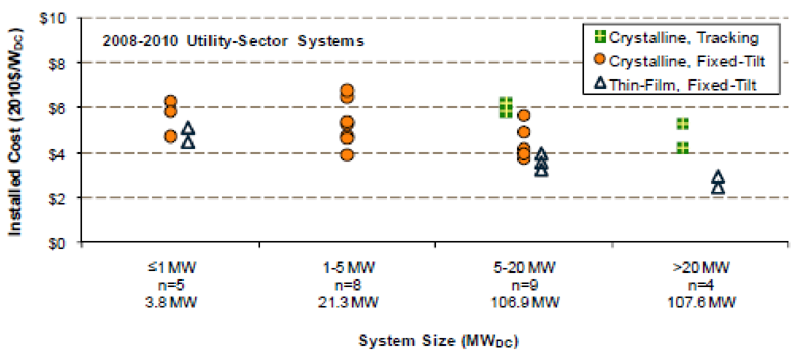

Figure 3-25. Installed Cost Variance Based on System Size. [44]

Table 3-7. Average Installed Cost Data (Dean and Haase, 2008).

System Size	Average Installed Cost ($/DC-watt)	Minimum Installed Cost ($/DC-watt)	Maximum Installed Cost ($/DC-watt)	Standard Deviation	Total Number of Projects
Less than 10 kW	8.32	3.73	17.99	1.44	5,885
Between 10 & 100 kW	8.03	4.03	17.78	1.36	808
Larger than 100 kW	6.87	4.27	15.76	1.30	381

[43] Lawrence Berkley National Laboratory, *Tracking the Sun IV: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010*, September 2011, pp.3-4.
[44] Lawrence Berkley National Laboratory, *Tracking the Sun IV: An Historical Summary of the Installed Cost of Photovoltaics in the United States from 1998 to 2010*, September 2011, p. 42

A preliminary design of a candidate system would clearly show the cost contributions to the initial project cost based on the number of components required, which have changed over the past several years. DOE shows the components of the installed cost on a dollar per watt basis (Figure 3-26).

Based on this, the module accounts for 2.15/3.80 $ per watt = 57 percent of the installed cost in 2010. Examination of the LCOE components in the FEMP Report indicated that when fixed and variable O&M costs are removed, the module costs accounted for 17.5/23 cents per kWh = 76 percent of LCOE in 2008. This indicates that decreased module prices will have a large impact of reducing the project LCOE overall based on the assumptions made in the original analysis.

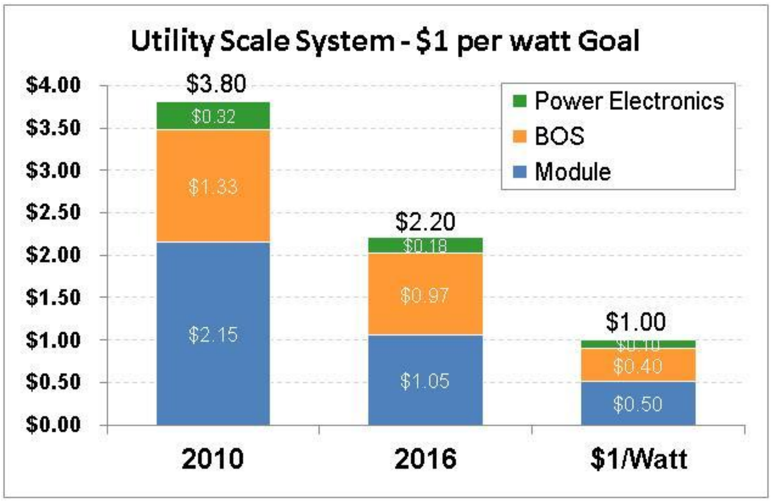

Figure 3-26. Photovoltaic System Cost (including installer margin) for Utility Scale Photovoltaic Systems in 2010. [45]

According to the *Sixth Northwest Conservation and Electric Power Plan*, a 20 MW reference PV plant (one axis tracking polycrystalline PV) could "yield capacity factors up to 26 percent at the best Northwest locations. If constructed in the near-term, this plant would deliver energy at about $280/MWh. Costs are expected to continue to decline at the historical average rate of about 8 percent/year." [46]

3.5.1.4 Cost Lifecycle Considerations

Deployment of PV systems in the Mid-Columbia region would require consideration of available resources on the ground, site-related transportation issues, environmental constraints, and design/engineering considerations due to site conditions.

Integration of PV into the existing power grid may be analyzed, taking advantage of the existing transmission lines and substations. Interconnection studies are still required and impacts on grid

[45] "Extreme Balance of System Hardware Cost Reductions (BOS-X)," U.S. Department of Energy Funding Opportunity Announcement (FOA) Number: DE-FOA-0000493, April 8, 2011.
[46] *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010, p. 6-27.

stability resulting from the intermittent nature of PV must be assessed. Small-scale PV may be deployed near the load and is easier to permit at smaller scales.

Since PV/solar electric is extremely modular in nature, multiple projects or multiple phase projects may be used to expand clean energy power generation deployment over time (e.g., in 1 MW phases). Phased deployment limits the amount of capital required at a given time, minimizes impacts due to construction, and avoids requirements for a large labor force in remote areas. On the other hand, phased deployment makes PV projects more complex for third party developers, may require multiple PPAs, and introduces a risk related to changing incentives.

Environmental impact studies may be required as part of the project permitting process. The need for road access, interconnections, drainage, maintenance access, and setbacks all contribute to site selection and project layout activities. For distributed (rooftop) PV and new construction (BIPV), initial deployment activities take less time.

The transportation network in the region is adequate to support construction of the comparatively small and modular PV system components; therefore, there is no anticipated need to construct additional access roads.

3.5.1.5 Long-Term Development Considerations

Based on the short time required for permitting and construction, large PV projects in the Mid-Columbia region may provide reasonably prompt payback. To limit uncertainties in production based on solar insolation, ground station collected meteorological stations should be installed at high-potential solar energy sites. These stations are relatively inexpensive ($13,000) and would help third-party developers establish the framework for a PPA. PPA durations are typically from 20 to 30 years.

3.5.1.6 Risks

Since the maturity of PV components is high overall, there are few technical risks in using this form of technology. The largest technical risk is in reliability of the large centralized inverters. Large inverter manufacturers now seem to favor condition-based maintenance instead of designing for 25+ year reliability. Use of micro-inverters could mitigate this risk, as micro-inverter cost and performance is becoming competitive with the large centralized inverters.

Financial risks become known when project developers perform feasibility studies for PV projects. Project ownership may change after initial developers/owners construct the project and the ITC benefit is realized. New large-scale PV project owners must have adequate margins to support ongoing O&M to maintain the level of production negotiated in the original PPA.

3.5.1.7 Path Forward

Conditions for the deployment of PV systems in the Mid-Columbia region have improved since the original study was performed in 2008. There is more past precedent for construction of large-scale PV and distributed (rooftop) PV systems. Overall:

- PV system costs have decreased (especially modules prices)
- PV deployment has increased over the past several years and the technology is more mature, therefore, more bankable

- Increased state incentives would increase the deployment of commercial- and residential-scale PV, thereby increasing the pool of qualified labor resources for Mid-Columbia regional projects.

PPA based PV projects should now be financially viable, which is a change from the conclusions in the FEMP Report.

Development of PV projects would be assisted by accomplishing the following:

1. Establish a PPA framework between all parties involved to encourage third-party developers to consider large-scale PV projects. This would encourage project feasibility efforts to be made by developers for selected areas in the region and provide new economic analysis based on commercial equipment prices.
   - Economic analysis similar to the ones contained in the FEMP Report should be conducted for 5 MW ground-mounted PV, using bottoms-up pricing considering different panel types and tracking options. Economic analyses are based on a PPA and consider existing and planned federal and state financial incentives.
2. To accelerate the deployment of cost-effective solar energy generation, consider implementing a strategy similar to DOD's Net Zero Energy Initiative (NZEI) for the federal sites in the region.
   - The NZEI that was launched by the DOD for bases and facilities, having the following key energy targets:
     - Reduce facilities energy intensity by 30 percent by 2015 and 37.5 percent by 2020 (2003 baseline)
     - Produce or procure 25 percent of facilities energy from renewable sources by 2025
     - Reduce Scope 1 & 2 GHG emissions from facilities by 34 percent by 2020 (2008 baseline).

The process and the NREL reference are shown in Figure 3-27.

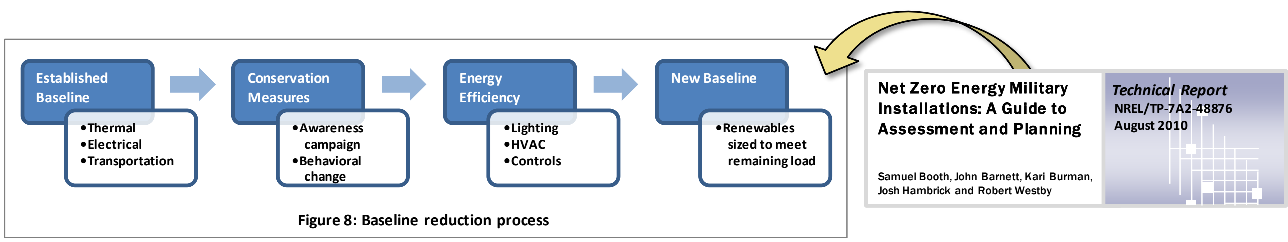

Figure 3-27. National Renewable Energy laboratory Report for U.S. Department of Defense Net Zero Energy Initiative.

3.5.2 Concentrated Solar

For CST designs, the key parameter is the DNI, measured in kWh/m^2, rather than the global irradiance used for PV resource assessments. The DNI is the component of sunlight that can be reflected and concentrated on a heat absorbing structure, such as a pipe or a gas reservoir for a Stirling engine. The actual DNI for an area is dependent on local micro-climate and shading, but average DNI is available from NREL and other data providers. The average annual DNI in Yakima, for example, is 1,719 kWh/m^2. By comparison, the average annual DNI in the California desert where the Solar Electricity Generation Stations were built in the late 1980s is 2,791 kWh/m^2, 62 percent higher than in Yakima.

Concentrated Solar Power Summary

- The DNI component of sunlight governs CSP system performance.
- Rooftop concentrated solar hot water systems are economical given area DNI, and should be incorporated into new buildings to defray HVAC heat and cooling loads.
- No significant technology changes since the NREL report was generated.

There are various solar thermal technologies in the market today. Parabolic trough plants have been built since the 1980s and are continuing to be built in the United States and in Spain. In these plants, parabolic line focus mirror systems direct the sun's rays onto heat absorbing receivers. Heat transfer oil flows through these receivers and carries the heat to the power block, where the heat generates steam to turn a turbine. The maximum practical temperature achievable to date is 400°C, making the heat a good fit for integration with the HRSG of a combined cycle power plant. In contrast, a power tower plant uses heliostat two-axis tracking mirrors to direct sunlight onto a central receiver. These plants tend to use molten nitrate salt as the heat transfer fluid, increasing the maximum upper temperature to 550°C. This HRSG input temperature increases the overall plant efficiency and saves money by allowing the use of a standard steam turbine rather than the modified lower-temperature steam turbine that the parabolic troughs require.

Two small power tower type plants have been built in Spain, one demonstration plant by Abengoa, and one commercial plant by SENER, both at less than 20 MW nameplate rating. Finally, Dish-Stirling systems use parabolic dishes to concentrate sunlight onto the hot gas reservoir of a Stirling engine mounted at the dish focal point. Stirling Energy Systems has had systems at the Sandia National Laboratory for testing for several years, but they have not been deployed commercially, and Stirling Energy Systems' parent company has recently filed for Chapter 7 Bankruptcy protection. Power generation via parabolic troughs would use a plant layout similar to that shown in Figure 3-28.

In this design, the parabolic troughs in the solar field collect heat which is then carried to the heat exchangers by the heat transfer fluid. When the plant is producing power, the heat is directed to the steam generator, solar preheater, solar superheater, and solar reheater. When the plant is storing heat for later use, the heat transfer fluid is directed to the storage heat exchangers and heat is used to increase the temperature of the molten nitrate salts in the storage tanks. Including storage, this allows the facility to make practical use of days that have extra solar production, and also allows the facility to provide power for longer durations and/or dispatch during early evening peak electrical demand on the grid.

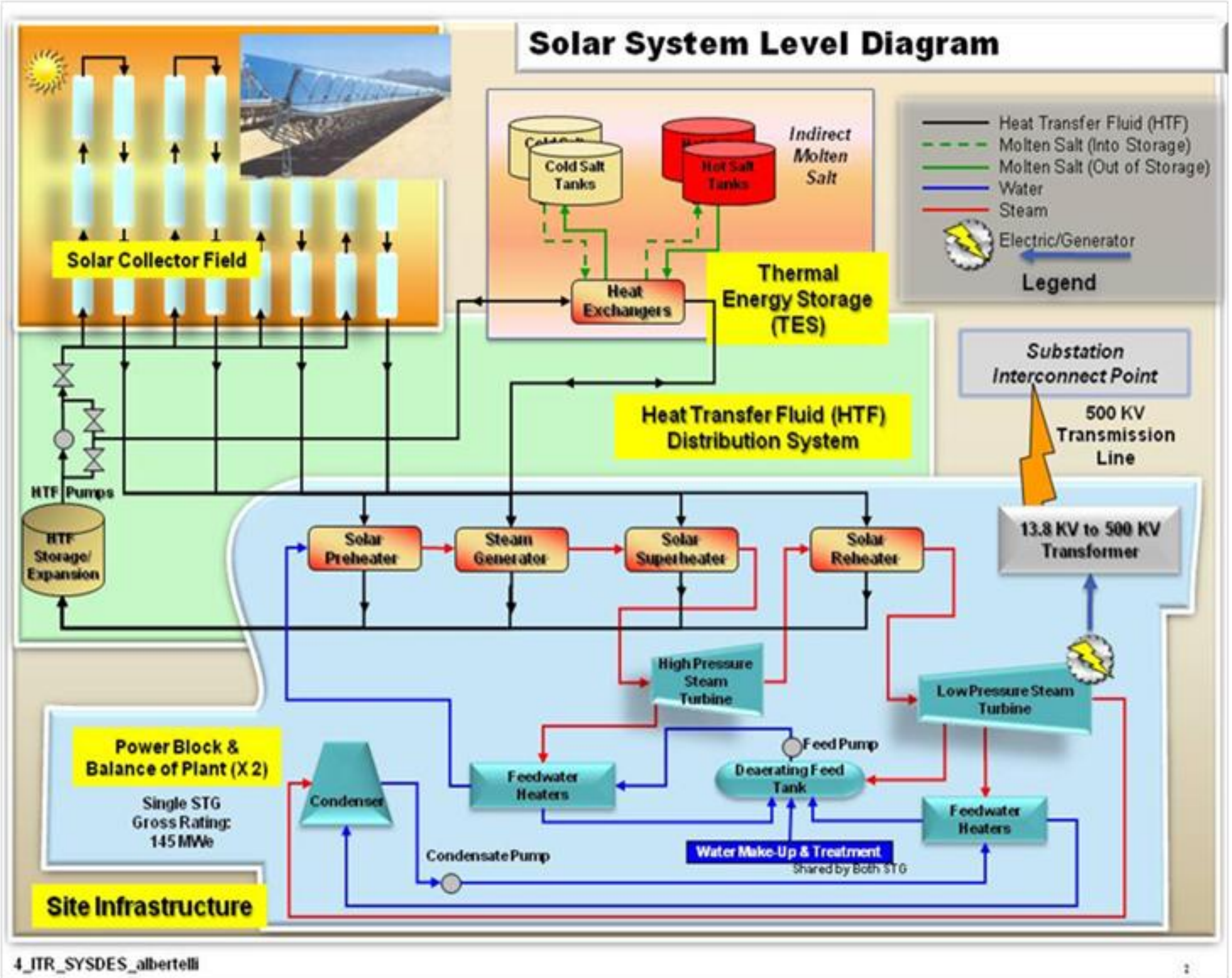

Figure 3-28. Typical Parabolic Trough Plant Architecture, Including Indirect Two Tank Molten Salt Thermal Storage.

A typical parabolic trough plant without storage would have roughly the same capacity factor as a PV single-axis tracking facility, while a plant with storage would have an increased capacity factor in proportion to the size of the storage facility. Even a large storage facility, however, would have a hard time reaching 35 percent capacity, defined as actual production per year/theoretical production per year if the plant generated its nameplate rating all 8,760 hours in the year.

A parametric analysis of parabolic trough options for solar field size and evaporative cooling versus dry cooling is shown below. The net annual energy production and LCOE are shown in the following tables. Table 3-8 shows results for evaporative cooling and Table 3-9 for dry cooling. Note that the LCOEs do not reflect any ITC or production tax credit. Inclusion of the 30 percent ITC would reduce LCOE by 6 to 8 cents/kWh depending on the cost of the rest of the capital raised for the plant.

Table 3-8. Evaporative Cooling parametric Analysis for Solar Field Size.

Evaporative cooling	SM 1.4	SM 1.5	SM 1.6	SM 1.7	SM 1.8	SM 1.9	SM 2.0	SM 2.1
1st year PPA Price	31.2	29.8	28.8	27.9	27.3	26.7	26.3	26.1
kWh/kW	1,398	1,511	1,614	1,729	1,823	1,927	2,022	2,096
LCOE, Real	35.3	33.7	32.5	31.3	30.5	29.7	29.1	28.8
Net annual production, kWhr	104,403,000	112,900,000	120,541,000	129,149,000	136,150,000	143,982,000	151,009,000	156,592,000
Q dump, MWhr, thermal	25	29	22	23	738	2,917	6,949	12,298
Plant Capacity Factor	16%	17%	18%	20%	21%	22%	23%	24%

Table 3-9. Air-Cooling Parametric Analysis for Solar Field Size.

Air-cooling	SM 1.4	SM 1.5	SM 1.6	SM 1.7	SM 1.8	SM 1.9	SM 2.0	SM 2.1
1st year PPA Price	32.5	31.1	30.1	29.0	28.4	27.8	27.4	27.2
kWh/kW	1,340	1,450	1,549	1,660	1,750	1,852	1,945	2,017
LCOE, Real	36.8	35.2	33.9	32.6	31.7	30.9	30.2	29.9
Net annual production, kWhr	100,097,000	108,318,000	115,712,000	123,967,000	130,738,000	138,366,000	145,308,000	150,667,000
Q dump, MWhr, thermal	25	29	22	24	839	3,043	7,090	12,464
Plant Capacity Factor	15%	16%	18%	19%	20%	21%	22%	23%

As can be seen from the tables, the LCOE is marginally better for the evaporative cooling architecture than for the air cooling architecture due to the increased power consumption of the air cooling fans compared to the evaporative cooling tower. In neither case is the system economically competitive with a fossil fuel installation such as a combined cycle power plant. However, a solar field installation to provide additional heat to the bottoming cycle of the combined cycle plant, as was done at the Martin Next Generation Solar Energy Center, Martin County, Florida would be more cost competitive since only the solar field would need to be built, and since the power would be most available in the summer time when the hydro power and wind power on the grid is less available than during the spring. While the Martin facility is the first instance of an existing combined cycle plant being paired with a new solar field, it is on-line and operating properly. In addition, many integrated solar and combined cycle plants are on the drawing board, typically with the solar component supplying 10 to 15 percent of the overall heat input to the steam turbine.

In contrast to the 400°C output and specialized receivers of the parabolic trough field, solar hot water systems only need to reach 95°C and use water in black chrome tubes or similar material to absorb the heat. These solar hot water systems are not appropriate for electrical power generation, but can easily be used for district heating or cooling. Thirty-ton chiller systems are available that use 95°C hot water and have an efficiency of 60 percent (50 ton heat input). Where the parabolic trough system has an indicative LCOE of 28 to 31 cents/kWh, the hot water system has an LCOE of 3.8 to 4.3 cents/kWh; i.e., far better cost effectiveness. There would be a slightly higher building cost for the industrial park since the roofs and load-bearing walls would have to be stronger to account for the weight of the collector and the water, but the payback would be within a few years given the very low cost of the solar fuel when used to displace natural gas or electricity consumption for heating, ventilation, and air conditioning (HVAC) loads.

Table 3-10 summarizes the strengths and weaknesses of existing CST technology.

Table 3-10. Strengths and Weaknesses of Concentrated Solar Thermal Power.

Parabolic Trough		Rooftop Hot Water	
Strengths	**Weaknesses**	**Strengths**	**Weaknesses**
Suitable for direct electrical power generation	Marginal solar resource in the Mid-Columbia region for generating power	Mature technology	Can't directly generate power
O&M jobs created for steam plant maintenance and mirror cleaning	Current capital expense still high	Can replace HVAC power use and, therefore, yield GHG offset RECs for HVAC needs	Low R&D component; not a high-value job generator
Can integrate well with natural gas power generation	Needs thermal storage to achieve dispatchability	Heat can also be used for low temperature processes such as greenhouse support	
Can achieve dispatchability via thermal storage		Very low LCOE, especially compared to parabolic trough	
		Does not take up acreage beyond the roof, unlike parabolic trough	

GHG = greenhouse gas.
HVAC = heating, ventilation, and air conditioning.
LCOE = levelized cost of energy.
O&M = operations and maintenance.
R&D = research and development.
REC = renewable energy credits.

3.5.2.1 Phased Deployment

The parabolic trough system does not lend itself to phased deployment unless a twin turbine power block is used, in which case half the field could be built at a time and connected to one turbine. This could certainly be done, and a pair of 50 MW power blocks would match current parabolic trough plant architecture in the Spanish market. Another alternative is to start without storage and build it in later. This generally is not recommended because without storage the plant would require ancillary services and spinning reserve to counteract production fluctuations. These fluctuations, while less severe than PV plant or wind plant fluctuations due to the thermal mass of the parabolic trough plant, still must be dealt with unless there is a place to store heat during plant operation.

The rooftop hot water heater does lend itself to phased deployment, since systems and absorption chillers can be installed as the buildings are erected, rather than being deployed all at once at the end of construction.

3.5.2.2 Risks

The main risk for both of these technologies is in the supply chain, which is a larger risk for parabolic trough than for the rooftop hot water system. For parabolic trough there are only two main vendors for the evacuated tube receivers. Those companies have significant investment from larger energy sector companies such as Siemens, but that investment comes with risks that the larger companies will withdraw it, leaving the manufacturers starved for capital. There is also political risk to the parabolic troughs because the market remains almost entirely dependent on feed in tariffs for its profit. Finally, there is a risk that as long as natural gas prices stay below \$8/MM Btu, peak electricity prices will also stay low, negating the entry point for parabolic trough plants in general into the United States market landscape and further diminishing the parabolic trough supply chain.

3.5.2.3 Summary

Parabolic troughs could be considered, but are of marginal utility given the average solar resource in the Mid-Columbia region, and the still-large capital cost if the plant must build its own power block. A parabolic trough field to provide heat to an existing steam turbine or process heat for existing industrial activities would have some promise. A rooftop hot water system should be integrated regardless of any other development as a good practice for GHG reduction via district heating and absorption chilling to replace electricity driven HVAC compressors and natural gas furnaces.

3.6 WIND POWER

According to the American Wind Energy Association, Washington State currently ranks fifth in total overall wind power installation in the United States. Wind energy generation deployed in the local Tri-City region may be considered; however, there is excess production from this type of clean energy power generation resource, forcing curtailment by the BPA in 2011. Therefore, deployment of additional large-scale wind power generation is not recommended; however, distributed wind power generation may be considered at smaller scales based on the grid conditions and available resources.

Wind Energy Summary

- Wind energy generation has been widely deployed in the region, and due to grid management requirements, production has been recently curtailed.
- Ancillary services required to stabilize grid conditions may provide an opportunity to deploy energy storage at grid interconnections in the Mid-Columbia region.

The purpose of this section is to characterize opportunities for the utilization of wind power systems in the Mid-Columbia region and to assess changes since the FEMP Report was published. The use of gas turbines and thermal resources to firm wind power dispatch and/or provide ancillary services to support the grid is discussed in the following section.

3.6.1 Wind Power Generation Application

The wind capacity in the region has been reached. According to the *Sixth Northwest Conservation and Electric Power Plan*:

> *"Wind power in the Northwest has variable output and little firm capacity and therefore requires supplemental firm capacity and balancing reserves. An existing surplus of balancing reserves and firm capacity within the Northwest has enabled the growth of wind power without the need or cost of additional capacity reserves. However, the concentration of installed wind capacity east of the Columbia River Gorge and within a single balancing area (Bonneville) has led to*

significant ramping events, putting pressure on Bonneville's ability to integrate additional wind development." [47]

Wind can be used to generate electricity using wind turbines at various scales, depending on the available resources in the area. Most deployment of wind at the utility scale takes the form of Horizontal Axis Wind Turbines (HAWT). The nature of the generation is intermittent, as shown by the BPA forecast in Figure 3-29.

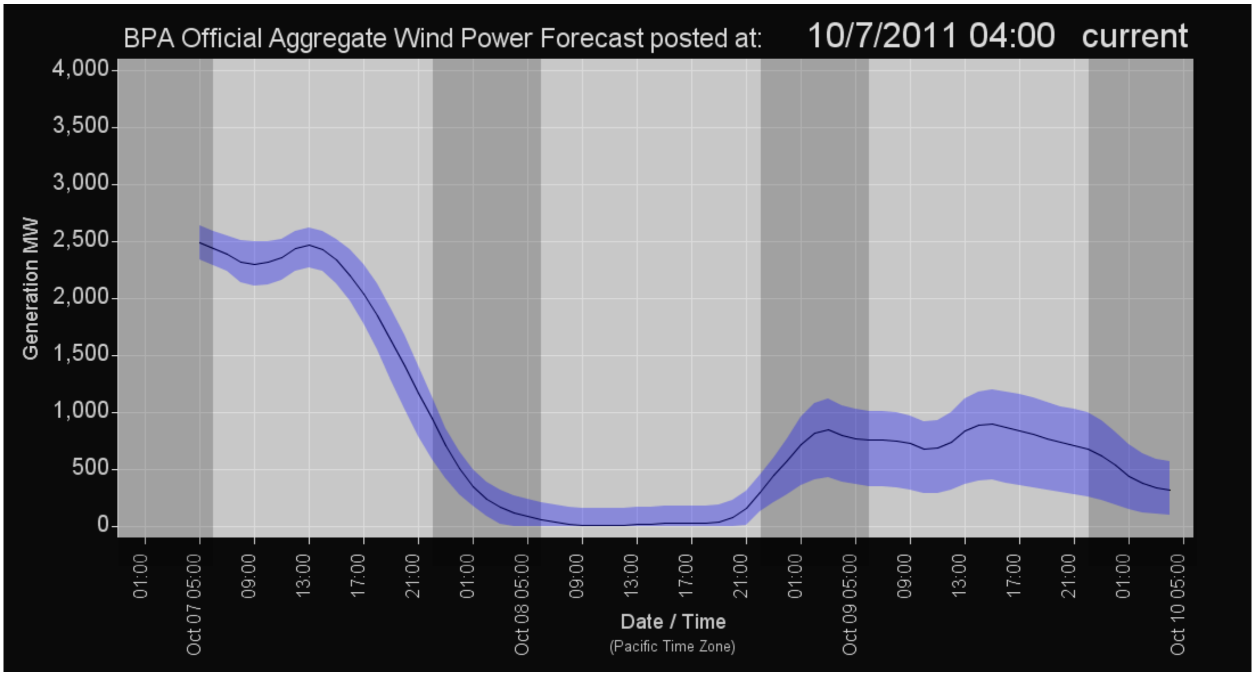

Figure 3-29. Bonneville Power Administration Aggregated wind Generation Forecast. [48]

Wind conditions vary based on the time of day and the season. The obvious challenge is to manage wind on the electric grid, and deployment of wind generation over 30 percent is known to destabilize the grid, necessitating ancillary services such as voltage regulation and frequency management. In addition, wind blows during off peak periods, which increases the challenge for utilities and Regional Transmission Organizations/Independent System Operators. Large-scale wind invites the building of large-scale energy storage capabilities.

Large-scale wind is characterized by large turbines (> 500 kW) placed in arrays. Small-scale wind uses smaller turbines, either HAWTs or vertical axis wind turbines of various geometries.

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[47] *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010, pp. 6-29.
[48] BPA, downloaded from www.bpa.gov/go/windforecast.

3.6.2 Region-Specific Feasibility Assessment

Decentralized wind and PV deployment could reduce the need for power and energy storage at building complexes, since their generation periods generally offset each other. Figure 3-30 shows a comparison of solar and wind clean energy generation.

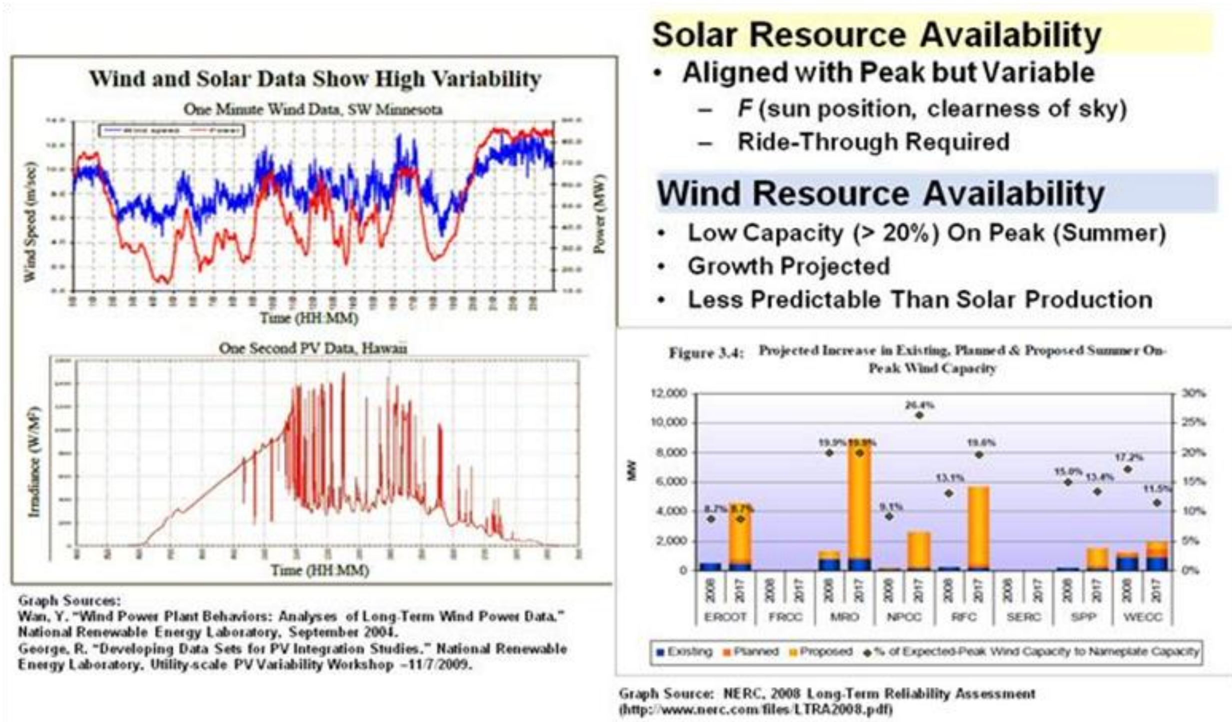

Figure 3-30. Comparison of Solar and Wind Renewable Energy Generation Characteristics.

The need for energy storage to provide reserve capacity for BPA is readily apparent based on the impacts of wind on the regional grid. At this large scale, practical energy storage approaches take the form of either compressed air energy storage (CAES) or pumped hydro energy storage (PHES). Use of CAES has been considered to store wind-generated energy.[49] Because CAES require underground caverns to store compressed air, and use gas turbines, deployment is very site dependent. One project has been built in the United States (150 MW in McIntosh, Alabama). For this reason, PHES appears to be a more viable form of energy storage for the local Tri-City region. There is also the possible availability of man-made high pressure air storage vessels for short-term storage, which would reduce the dependency on site conditions; however, there are no known deployments of this technology.

3.6.3 Engineering and Economic Evaluation

Additional deployment of grid-connected wind turbines does not seem viable for the future, however, economical analyses for energy storage systems should be conducted based on capital and O&M costs in relation to revenues for ancillary services, and perhaps capacity peaking.

[49] CNET Article "Compressed-air storage coming to wind power," http://news.cnet.com/8301-11128_3-10026958-54.html

Gravity Power, LLC advertised a cost of $1,000/kW for ancillary services. A PPA arrangement would be the most beneficial to deploy wind generating assets.

3.6.4 Risks

Deployment of wind generation assets beyond those currently installed or planned in the Mid-Columbia region bear the risk of not being permitted based on grid conditions. There is some performance risk also, based on wind resources for specific localities. Small wind turbines may be cost effective; however, PV deployment appears to be a more cost-effective option.

3.6.5 Conclusions

The following conclusions were reached based on the feasibility study:

- Additional large-scale wind generation should focus on integration with energy storage to help stabilize the existing grid system
- Additional wind power should be given a low priority when new clean energy generation options are considered.

3.7 GEOTHERMAL

3.7.1 Technology Description and Application

Geothermal Summary

- Deep, utility scale geothermal power is not a likely candidate in the Mid-Columbia region due to the local geology.
- Shallow, groundwater systems show promise for heating and cooling applications in the region.

Shallow geothermal resources (from surface to several thousand feet [meters], $T^{o}C < 100$) can provide direct use heating and cooling applications using geothermal or ground source heat pumps (GHP). GHPs are either open-loop or closed-loop systems (Figure 3-31).
In open-loop GHP systems, the supply water is used once and comes from a well, stream, or pond and then the water is discharged back into the ground after being pumped through the heat pump. Closed-loop GHPs transfer heat to or from a fluid rather than to or from air, so no backup heat source is required. In winter the loop fluid absorbs stored ground heat and carries it indoors (e.g., out of the building at 35^{o}F, back in at 45^{o}F). In summer the loop fluid absorbs heat from the building and carries it through the earth loop and deposits heat in the cooler earth (e.g., out at 85^{o}F, back in at 77^{o}F).

Deep geothermal resources (2 to 6 miles [3 to 10 km], $T^{o}C > 100$) can produce electricity and heat using enhanced (or engineered) geothermal systems (EGS). DOE has broadly defined EGS as engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources. EGS includes all geothermal resources that currently are not in commercial production and require stimulation or enhancement to produce electricity and heat for direct application.

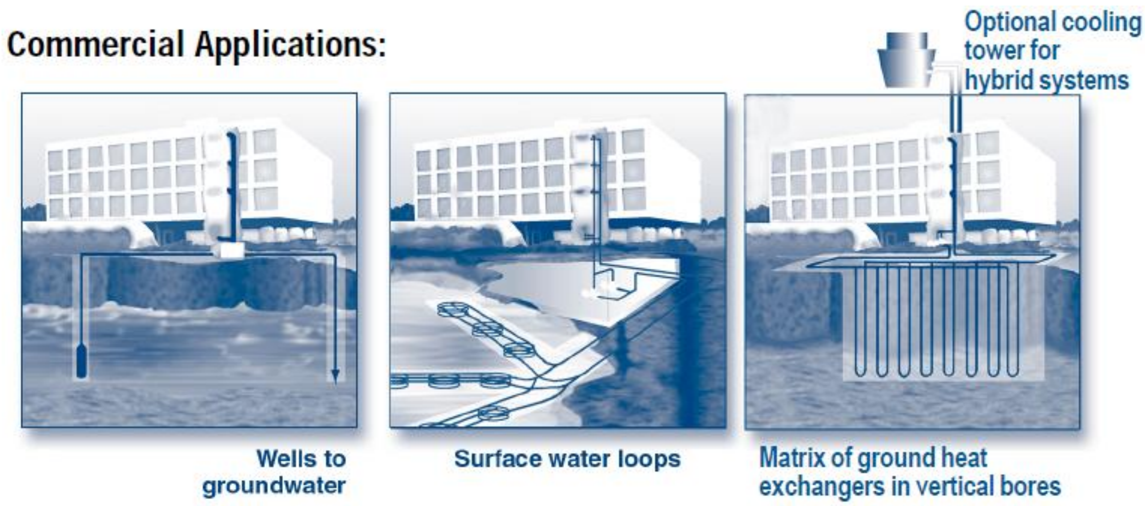

Figure 3-31. Various Shallow Geothermal Source/Sinks that can be Applied to Geothermal Heat Pumps in Commercial Applications (DOE/EE-0258).

EGS includes conduction-dominated, low-permeability resources in sedimentary and basement formations, as well as geopressured, magma, and low-grade, unproductive hydrothermal resources. EGS concepts would recover thermal energy contained in subsurface rocks by creating or accessing a system of open, connected fractures through which water can be circulated down injection wells, heated by contact with the rocks, and returned to the surface in production wells to form a closed loop (Figure 3-32).

3.7.2 Region-Specific Feasibility

The geology of the Mid-Columbia region is an important factor in assessing the feasibility of utilizing geothermal as a clean energy source. In general, the geology consists of unconsolidated to semi-consolidated sediments overlying the Columbia River Basalt layer. The sediment thickness ranges from 0 to over 600 ft (183 m) and groundwater is located from 220 to 350 ft (67 to 107 m) below ground surface in the region's typical plateau areas. The basalt consists of numerous flows and interbedded sediments and is over 10,000 ft (3 km) thick beneath the much of the Mid-Columbia region's plateau areas ("The Geologic Evolution of the Central Columbia Plateau" [Reidel et al. 1989]). Although drilling has not penetrated the base of the basalt, sedimentary rocks may underlie the basalt (*Roadside Geology of Washington*, [Alt and Hyndman, 1984]).

INEEL/MIS-2002-1622, *Washington Geothermal Resources*, show most of the Mid-Columbia region within a region of known or potential geothermal resources with most wells (completed in the basalt or overlying sediments) having bottom hole temperatures from 20°C to 50°C. One well near Rattlesnake Mountain had a bottom hole temperature of 96.3°C at 8,200 ft (2.5 km) depth ("Geothermal Resources of Washington, Geologic Map GM-25" [Korosec et al. 1981]). "Geothermal Resource of the United States, Locations of Identified Hydrothermal Sites and Favorability of Deep Enhanced Geothermal Systems (EGS)" (Roberts 2009) classified the region as moderately favorable for deep EGS, about mid-range on the favorability scale considering the geothermal resources of the entire United States.

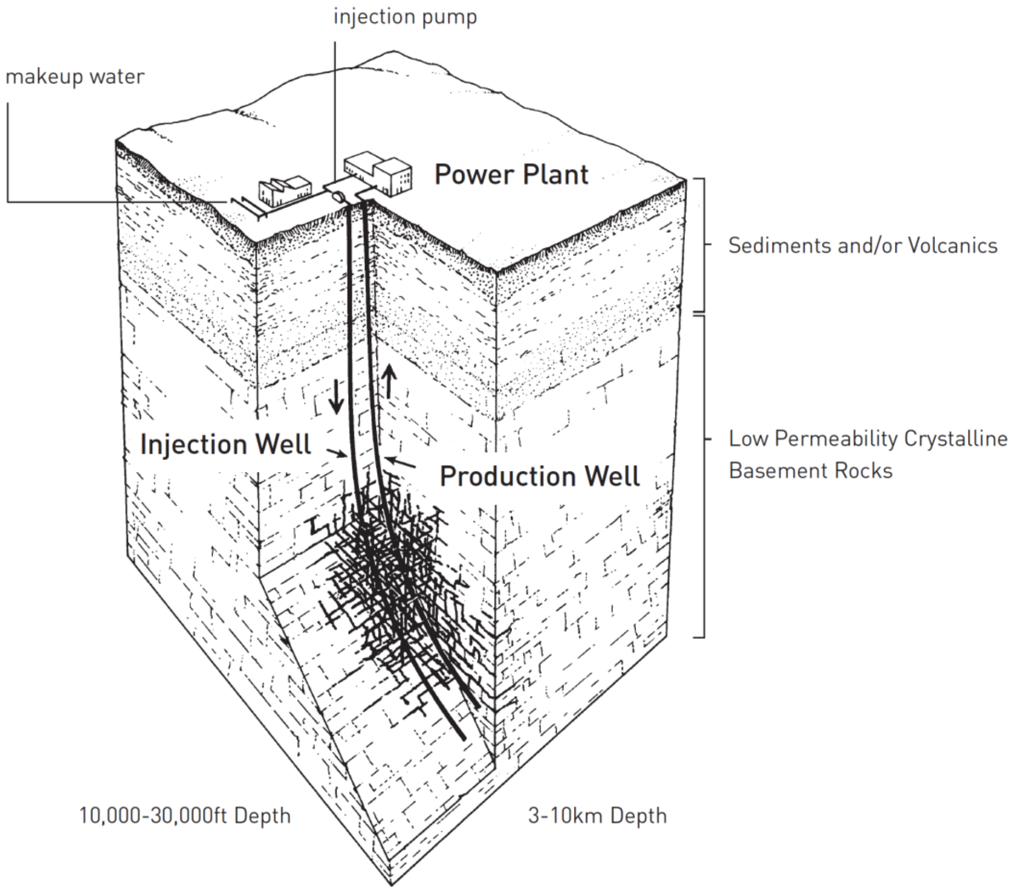

Figure 3-32. Schematic of a Conceptual Two-Well Enhanced Geothermal System in Hot Rock in a Low-Permeability Crystalline Basement Formation (MIT 2006).

Figure 3-33 shows that at a depth of 2 to 6 miles (3 to 10 km) beneath the region, the estimated temperature is 100° to 250°C.

In September 2011, DOE invested $38 million over 3 years in 32 innovative projects to develop and test new ways to locate geothermal resources and improve resource characterization, drilling, and reservoir engineering techniques, which will enable geothermal energy sources to help reduce the nation's reliance on fossil fuels (Geothermal Technologies Program). Development of an EGS power plant in the Mid-Columbia region would benefit from this investment but would still require a multi-year effort. The first step would be exploration to identify and characterize the best candidate sites for exploitation. Holes would then need to be drilled deep enough to encounter useful rock temperature to further verify and quantify the specific resource at relevant depths for exploitation (estimated at between 2 and 6 miles [3 and 10 km]). If low-permeability rock is encountered, it would be stimulated hydraulically to produce a large-volume reservoir for heat extraction and suitably connected to an injection-production well system (Massachusetts Institute of Technology [MIT] 2006).

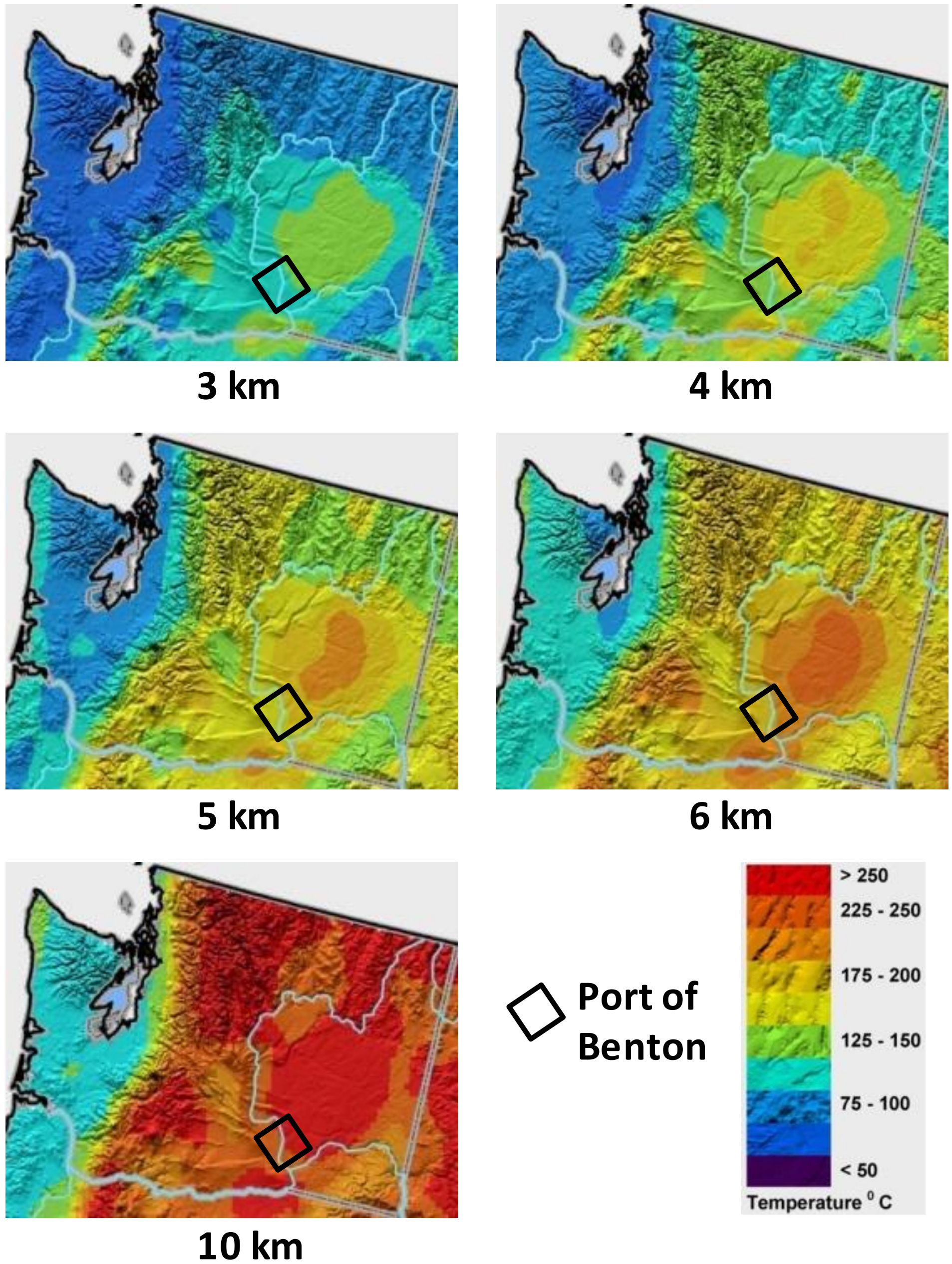

Figure 3-33. Estimated Temperatures Beneath the Mid-Columbia Region (INL 2005).

3.7.3 Engineering and Economic Evaluation

EGS development and design is based on a few projects and significant experience with oil and gas well drilling. The following EGS information is summarized from MIT (MIT 2006). Figure 3-34 summarizes the duration, relative cost and risk for stages of EGS development.

Geologic assessment and permits

Category	Duration	Cost	Risk
Define areas of potential development	1-2 years	Moderate	Low
Exclude areas of public protection, high environmental impact, or protected zones	1-2 years	Moderate	Low
Determine regional high- to low-heat gradient zones	1-2 years	Moderate	Low
Correlate with areas of forecast demand growth or base-load retirement	1 year	Low	Moderate
Determine regional variations in drilling costs, labor costs, grid integration	< 1 year	Low	Moderate
Determine need for voltage and VARS[14] support	< 1 year	Low	Moderate
Determine regulation constraints.,	< 1 year	Low	Moderate
Determine taxation policies	< 1 year	Low	Moderate
Estimate market or government subsidies	< 1 year	Low	Moderate
Estimate costs	1 year	Low	Moderate
File for permit and mitigate environmental externalities	3+ years	High	High
Apply for transmission interconnect	< 1 year	Moderate	High
Acquire permit and begin drilling	1 month	Moderate	Low

Exploratory drilling

Category	Duration	Cost	Risk
Site improvement	1 month	Moderate	Moderate
Determine reservoir characteristics (rock type, gradient, stimulation properties, etc.)	6 months	High	High
Performance/productivity (flow rate, temperature, fluid quality, etc.)	6 months	High	High
Apply and test advances in drilling and fracturing technology	6 months	High	High
Achieve cost reductions as function of recent research and past learning curve	6 months	High	High

Production drilling and reservoir stimulation

Category	Duration	Cost	Risk
Apply best practices and further develop site	1 year	High	Moderate
Construct transmission interconnection	2 months	Moderate	Moderate
Construct power transmission facility	2 months	High	Moderate
Construct power conversion system	2 years	High	Low

Power production and market performance

Category	Duration	Cost	Risk
Bid long based on expected delivery costs	Routine and recurring	Low	High
Estimate competitive fuel and delivery costs for existing base-load power	Routine and recurring	Low	High
Enter power purchase agreement	Infrequent	Moderate	High

[14]Reactive energy (VARs) is defined as the imaginary component of the vector product of the voltage and current, each expressed as a vector and used to provide line stability.

Figure 3-34. Stages of EGS Development: Duration, Costs, and Risk (MIT 2006).

Initial EGS exploration costs in the region are difficult to estimate. Based on actual and modeled well drilling and completion costs, it would cost an estimated $3 million to $30 million (in 2004 dollars) to drill and complete each well to a depth of 2 to 4.3 miles (3 to 7 km). At least two production and several exploration boreholes would be needed.

The installed specific cost ($/kW) for either a conventional 1- or 2-flash power plant at EGS reservoirs is inversely dependent on the fluid temperature and mass flow rate. Over the range from 150 to 340°C: For a mass flow rate of 100 kg/s, the specific cost varies from $1,894 to 1,773/kW (1-flash) and from $1,889 to 1,737/kW (2-flash); for a flow rate of 1,000 kg/s, the cost varies from $1,760 to 1,080/kW (1-flash) and from $1,718 to 981/kW (2-flash).

The total plant cost, exclusive of wells, for a 2-flash plant receiving 1,000 kg/s from an EGS reservoir would vary from $50 million to $260 million, with a fluid temperature ranging from 150 to 340°C; the corresponding power rating would vary from about 30 to 265 MW. If the reservoir were able to supply only 100 kg/s, the plant cost would vary from $5.6 million to $45.8 million over the same temperature range; the corresponding power rating would vary from 3 to 26.4 MW.

3.7.4 Risks and Issues

EGS power lacks a demonstration of its capability at the present time. Although a few EGS reservoirs with connected wells have been developed in deep, high-temperature rocks, there are still many areas of technology improvement needed that will help make the process more economical and less risky (MIT 2006). The risks for each stage of EGS development are summarized in Figure 3-34.

3.7.5 Conclusions

EGS technology is still maturing and after its capability is demonstrated at more favorable sites in the western United States it may be appropriate in the future to consider evaluation and development of the deep geothermal resources Mid-Columbia region.

3.8 SMALL MODULAR NUCLEAR REACTORS

About 20 percent of the United States electricity comes from 104 nuclear power plants. Most reactors operating in the United States are more than 30 years old, with the last plant ordered in the 1970s. Although new capacity can be developed using abundant domestic supplies of natural gas, growth in power demand and loss of aging coal-fired and nuclear infrastructure will create a shortfall in capacity in the United States that will challenge the country's ability to create a new base load capacity of any kind.

The Case for Small Modular Reactors: Nuclear power, when appropriately designed, built, and operated, can provide abundant power safely, cleanly,

Nuclear Energy Summary

- Smaller, inherently safe, production lines for reduced cost to build.
- Designed for reduced manning and reduced operating cost.
- Standardized design in cooperation with the NRC for streamlined licensing leading to more rapid return on investment, to enhance attractiveness for investment.
- Consortium concept: Public/private partnership for shared cost of initial development to overcome R&D and capital costs for initial system development and fielding.

and without causing GHG emissions. Unlike other low-GHG emitting power sources, nuclear power can operate continuously and on-demand and is readily integrated into existing power distribution grids to ensure effective response to customer needs. It is likely that an advanced reactor could provide safe, secure, and economical power to DOD bases, both in the United States and abroad, as discussed in a recent Center for Naval Analysis study (CRM D0023932.A5/2REV, "Feasibility of Nuclear Power on U.S. Military Installations").

There is growing interest in small nuclear reactors that could be used to provide electric power safely and economically in areas where there is need for moderate power additions and where the large capital cost and long lead time for return on investment of present Generation III+ reactor designs makes them unaffordable for most of the utilities in the United States It is clear following the casualty at Fukushima Daiichi earlier this year that new reactors should be able to manage long-term reactor cooling following shutdown without depending on external power or other active means of cooling. It is highly desirable to not depend on other active components to mitigate a reactor casualty as well, but to depend instead on naturally occurring phenomena to the extent practical ("Small Reactor Development Advances Energy, Environmental Benefits in New Markets," [Nuclear Energy Institute 2011]; "Small Modular Reactors," [American Nuclear Society 2011]).

There are a number of small modular reactor designs being developed in the United States and abroad that can meet these enhanced safety goals. Large numbers of new reactors must be built in the United States in the coming years to replace older reactors that will reach the end of their lives if the current percentage of power produced by nuclear reactors is to be maintained. An even larger numbers of reactors must be built if they are to replace older coal-fired power plants, provide energy for industrial processes, or power electric vehicles.

3.8.1 Technology Description and Application

Small modular reactors are generally defined as having a power level of approximately 300 MW electrical or less. At such sizes, some of the reactor designs can be fabricated in factories, enabling considerable reduction in cost. The reactors themselves, or large power modules, can be shipped directly to the reactor site and erected with a minimum of skilled site labor. Serial production offers the potential for significant cost savings. Conventional analyses based on extrapolating earlier cost estimates for large reactors show a substantial increase in the cost per kW electrical capacity for small reactors. However, more recently, Westinghouse and B&W claim that the savings from serial production of reactors and plant modules in factories combined with simplifications in reactor systems result in costs essentially the same per unit of output power as for much larger reactors. Figure 3-35 shows a cutaway view of a prototypical small modular nuclear reactor design.

Figure 3-35. Prototypical Small Modular Nuclear Reactor.

Small modular reactor designs can be characterized by their primary reactor coolant:

- *Light Water Reactors* use ordinary water as both reactor coolant and moderator. All of the present designs keep this coolant under high pressure (on the order of 2,000 psi). The reactor heat is transferred to one or more steam generators, where secondary water is used in a conventional steam system to generate power. The reactor designs proposed by NuScale, B&W, and Westinghouse enclose these steam generators within the reactor vessel, along with primary pumps, control rods, and the coolant pressurizing system. The reactor vessel, along with the containment vessel that surrounds it, is located below grade. The major advantage of these light water reactors is that they are based on well proven reactor technology and are perceived to be the most practical to license. No new technology development is required to support the design and construction of these reactors.
- *Liquid Metal Reactors* use either sodium or a lead alloy as reactor coolant. Reactors based on sodium coolant were developed in the United States under the Integral Fast Reactor Program up to the mid 1990s. The main proponents of small sodium cooled reactors are GE-Hitachi and Advanced Reactor Concepts. No new technology is required to do the detailed design and support construction of GE-Hitachi's PRISM design. Sodium cooled reactors have demonstrated a degree of passive safety, both in abnormal operation and for after-shutdown cooling, which is quite remarkable.
- No *lead alloy reactor* has been built in the United States, but reactors using lead-bismuth coolant were deployed in the ALFA class of Russian submarines. The main proponent of lead-bismuth cooled reactors is Hyperion. Some development of core structural and fuel materials is likely required for a lead bismuth cooled reactor, depending on how much data can be obtained from the Russians and accepted by the U.S. Nuclear Regulatory Commission

(NRC). Liquid metal cooled reactor designs typically use steam generators to provide steam to a conventional steam cycle. However, liquid metal cooled reactors are well suited to use of a supercritical carbon dioxide power conversion cycle which offers several advantages over a conventional steam plant. Supercritical carbon dioxide power systems require engineering development to scale up existing small-scale demonstration systems.

- *Gas Cooled Reactors* are being developed with DOE funding under the Next Generation Nuclear Program. These reactors use helium as coolant and potentially could operate at much higher temperatures than would be practical for either light water or liquid metal cooled reactors. The present Next Generation Nuclear Plant Program is primarily focused on developing high-temperature materials, although a conceptual design is being developed by General Atomics.

In addition to producing power, small fast-spectrum liquid metal cooled reactors are capable of consuming the plutonium and higher elements that are left over in spent nuclear fuel from light water reactors. Burning these long-lived radiotoxic elements not only produces additional power, it also has a major impact on the amount of material that must ultimately be disposed of in a geologic repository. It also shortens the time these wastes must be isolated from hundreds of thousands of years to hundreds of years. There is currently no commercial market for such transmutation and consumption of wastes since the disposal of spent nuclear fuel is the responsibility of the U.S. Government in accordance with the *Nuclear Waste Policy Act of 1982*. Because of this, however, building and operating fast spectrum reactors, combined with a system to reprocess used fuel, would be of particular interest to the U.S. Government.

Other reactor technologies exist as well. There is no shortage of innovation in the area of reactor concepts; however, most of these would require long-term development of advanced materials and systems and many would require a proof-of-principle prototype be built and tested before a design for commercial application could be contemplated. Some of them may fill a role in our mid-term future.

3.8.2 Region-Specific Feasibility Assessment

The Mid-Columbia region has several characteristics that make it well suited for small modular reactor development. The area's workforce is well trained in nuclear technology and the surrounding communities are likewise receptive to working on nuclear systems. The Columbia River provides ample cooling and the stable geology and climate of the region reduce the opportunities for natural disasters that could damage reactors and limit their cost effectiveness or challenge their safety.

3.8.3 Cost

None of the small modular reactor designs is sufficiently complete for the reactor designer to submit a license application to NRC. Funding for light water and liquid metal cooled reactors to this point has come from the private sector. Achieving sufficient design maturity to submit a license application to NRC will take many millions of dollars of additional funding. The DOE FY 2012 budget has funding to help two private industry teams submit design license applications for light water reactors. This provision may not survive forthcoming budget challenges. The assumption typically is that once a design is approved, utilities will come forward to provide the funding to complete the detailed design and build the reactors. Completing the design to a level necessary to initiate fabrication of long-lead components and ultimately to begin construction will cost on the order of hundreds of millions of dollars.

Cost estimates for building and operating these reactors depend on a number of assumptions, which must be borne out in practice. GE-Hitachi estimated their PRISM reactor could be built for approximately $3.2 billion in constant FY 2007 dollars ("Global Nuclear Energy Partnership Business Plan" [GE-Hitachi 2008]). Most of the cost estimating work done by the reactor vendors is proprietary. Lockheed Martin has developed a cost-estimating tool based on available data to provide insight into the important cost drivers. This work confirms that capital costs are the major portion of the total cost of building and operating a nuclear facility amounting to more than 40 percent of the total.

Depending on how the reactor is financed, the cost of the capital also can be a major driver. For instance, the cost analysis done by the Center for Naval Analysis of small modular nuclear reactors for DOD bases estimates annual interest cost in the first years that exceed the annual cost of plant operations, staffing, and fuel purchases. A number of costs, such as the NRC annual license fee, do not presently depend on reactor rating and hence affect cost per kWh disproportionately for small modular reactors. The most important of these costs that do not scale with reactor power is the cost of the staff required to operate, maintain, and guard the plant. Lockheed Martin's estimate is that such labor costs can amount to as much as one quarter of the annual cost of owning and operating a small modular reactor if current staffing for a large reactor were applied instead to a small modular reactor. This would make such reactors uncompetitive in the commercial energy market.

3.8.4 Nuclear Regulatory Commission Licensing

There is reason to believe that a combination of favorable siting and taking advantage of the small plant's inherent passive safety would enable much smaller staffing. Reactor vendors have begun active discussions with NRC, but it is likely that changes to existing NRC regulations will be necessary. NRC has indicated their willingness to consider modifications to the present licensing requirements which are based on light water reactor technology, instead making requirements based on risk-based calculations. The transition from the present prescriptive licensing to this new methodology will likely take several years. The result is that light water reactors are likely to be licensable in a shorter time than more advanced reactors. An additional challenge is that NRC does not fully engage in such specific safety reviews until an actual license application is submitted and none of the reactor vendors for these small modular reactors has reached a point of submitting a detailed license application. To facilitate timely licensing of new reactor designs, the NRC should be funded in the near term to begin the process of regulatory reform necessary to make licensing advanced reactors practical. A predictable regulatory environment will be necessary to encourage the long-term investment by private enterprise, especially for advanced reactor designs.

3.8.5 Risks

Neither light water reactors nor sodium cooled fast reactors require development of new technology. Both of them can be built now. The greatest risks for either are in the long timeline to completion and in the NRC licensing process.

Light water reactor vendors, as well as GE-Hitachi have stated that a first of a kind small modular reactor of either type could be designed and built 10 years from now if funding were sufficient. The challenge is to find investors willing to tolerate these very long times. It may be that the initial investors will be rewarded when a utility buys the rights to a design, completes it, and builds it. In that case, the sums required to complete the project come from the utility ratepayers. More advanced concepts such as the sodium cooled reactor may involve too much perceived risk for this purely commercial approach to work, since additional changes to NRC licensing regulations will be required. While NRC has expressed willingness to transition to risk-informed regulation, this could take many years and such delays could jeopardize the financial support to complete the projects.

There are also risks of public acceptance of nuclear power, especially following the disaster at Fukushima Daiichi in Japan. Gaining this acceptance will require the reactor vendors to provide compelling evidence that their designs have such robust passive safety that events such as occurred at Fukushima Daiichi simply cannot occur. The need for new nuclear power is sufficiently compelling and it is likely that public acceptance can eventually be won.

3.8.6 Path Forward

The Mid-Columbia region could be a center for research, development, production, and operation of small modular reactors. The area possesses the right mix of natural and manmade resources, workforce, and political support for development to ensure success of a development effort.

There are several ways to overcome the various financial and regulatory hurdles to make small modular reactors a reality. One approach is being pursued by NuScale, B&W, and Westinghouse, which would result in a purely commercial program that depends ultimately on heavy financial support from a utility, or a consortium of utilities.

Another approach would be for the U.S. Government, working with a public-private consortium, to provide significant support to get the first-of-a-kind reactor system built and demonstrated. In this case, the government could encourage development of technologies such as liquid metal cooled fast reactors, combined with effective recycling of used nuclear fuels, which would help to solve problems of direct interest to the government. Such a development could provide the basis for a robust export product and would help to reestablish the United States' role as a leader in the safe, economic, and proliferation-resistant nuclear power. It is likely that an advanced reactor could provide safe, secure, and economical power to DOD bases, both in the United States and abroad, as discussed in a recent Center for Naval Analysis study. To facilitate such an approach, the NRC should be funded to begin the process of regulatory reform necessary to make licensing advanced reactors practical. A predictable regulatory environment will be necessary to encourage the long-term investment by private enterprise, especially for advanced reactor designs.

3.9 GRID SCALE ENERGY STORAGE

Some large power companies are beginning to deploy battery technology, despite not being cost competitive, in the hope that costs will come down as manufacturers scale up production. However, grid-connected storage still remains too expensive to be widely deployed. The existence of wind and hydro power generation in Washington State may improve the potential for the deployment of energy storage.

Energy Storage Summary

- Power and energy storage represents a complex opportunity.
- At a large scale, pumped hydro and compressed air energy storage may be economically viable to be deployed in the Mid-Columbia region. There have been improvements to traditional approaches.
- Although expensive, grid-connected battery storage projects may be deployed as pilot projects.
- Close coordination with the utility and grid managers is required to ensure grid conditions are optimal for use of power and energy storage.

3.9.1 Power and Energy Technology Application

Both the benefits and challenges of power and energy storage are situation specific. The main benefit of power and energy storage is increased deployment of clean energy generation.

Storage obstacles include the following:

- Power and energy storage represents a complex opportunity
- Modular storage has high costs when compared to base load power
- All storage benefits need to be aggregated
  - There are multiple stakeholders and beneficiaries
  - Utility point of view – the economy has depressed prices temporarily; however, electricity demand is expected to grow approximately 1.4 percent/year driven by population growth in the Pacific Northwest. Storage may be needed to firm intermittent resources such as PV and wind, and to put off investment in new transmission lines.
- Storage benefits must be optimized
  - Prerequisite to understanding need/situation
  - Complex cost/performance modeling is required.
- Little past experience in storage deployment (risk)
  - Deployment starting at utility scale.
- Regulatory permission is required
  - Mostly for distributed storage
  - Permitting/siting rules and regulations.
- Little system integration experience for these projects
  - Engineering standards and tools are now limited.
- Financing – bank guarantees

- Competition from other technologies and programs involving:
  - Advanced or distributed generation
  - Demand response
  - Smart grid
  - Clean energy deployment
  - Electric vehicles
  - Energy efficiency.

The ability to store energy is markedly lagging alternative power generation, and discounting batteries is currently an expensive proposition overall. There are three basic forms of storage, mechanical, thermal, and electric. Molten salt solutions, compressed air caverns, and graphite block solutions all release heat or air to drive a steam or air turbine to generate electricity. These solutions are in use around the world to various degrees of success, generally in large-scale utility applications, as required by their cost and complexity.

Due to the transient nature of solar and wind resources, some form of short-term power storage is required to smooth out fluctuations due to factors such as brief cloud cover. Additionally, longer-term energy storage may be deployed to provide dispatch of energy when it is most needed and when dispatch is most profitable. Figure 3-36 presents a comparison of solar and wind energy generation characteristics.

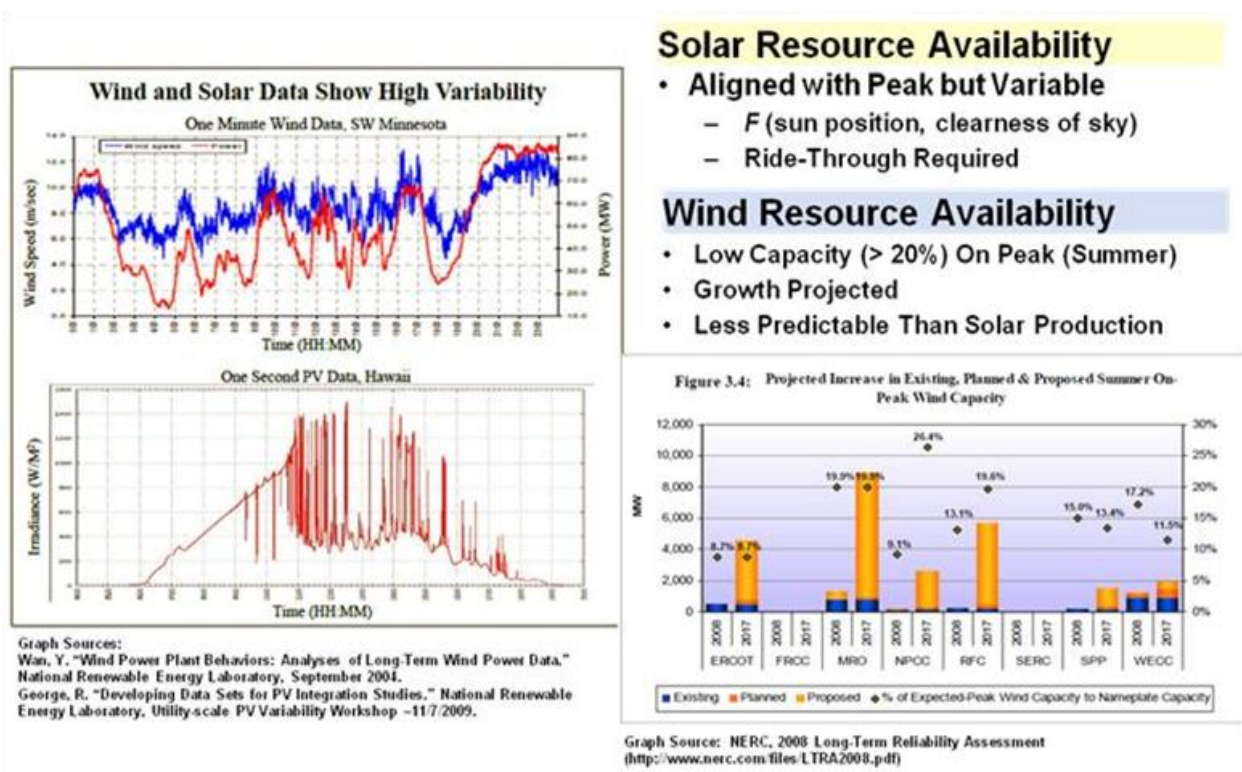

Figure 3-36. Comparison of Solar and Wind Renewable Energy Generation Characteristics.

The ideal energy storage device has high power and energy densities, charges and discharges quickly on demand, has a low self-discharge rate, has a long lifetime, and is safe for humans and the environment. In practice, selecting a storage technology requires some compromise between these characteristics and cost considerations. The most common types of energy storage for clean energy sources are batteries and flywheels, with supercapacitors and battery-supercapacitor hybrids also approaching commercial viability for some applications. Energy storage methods for utility-scale applications include CAES and PHES, briefly discussed here.

Conventional batteries (e.g., lead acid, Ni-Cad, Li-Ion), flow batteries (e.g., Zinc Bromide [ZnBr], Vanadium Redox [VRB], etc.), molten electrolyte batteries (NaS), direct electrical approaches (e.g., ultra-capacitors), and mechanical approaches (pumped hydro, compressed air and flywheel) are becoming commercially viable. A top-level list of various electric storage technologies are shown in Figure 3-37.

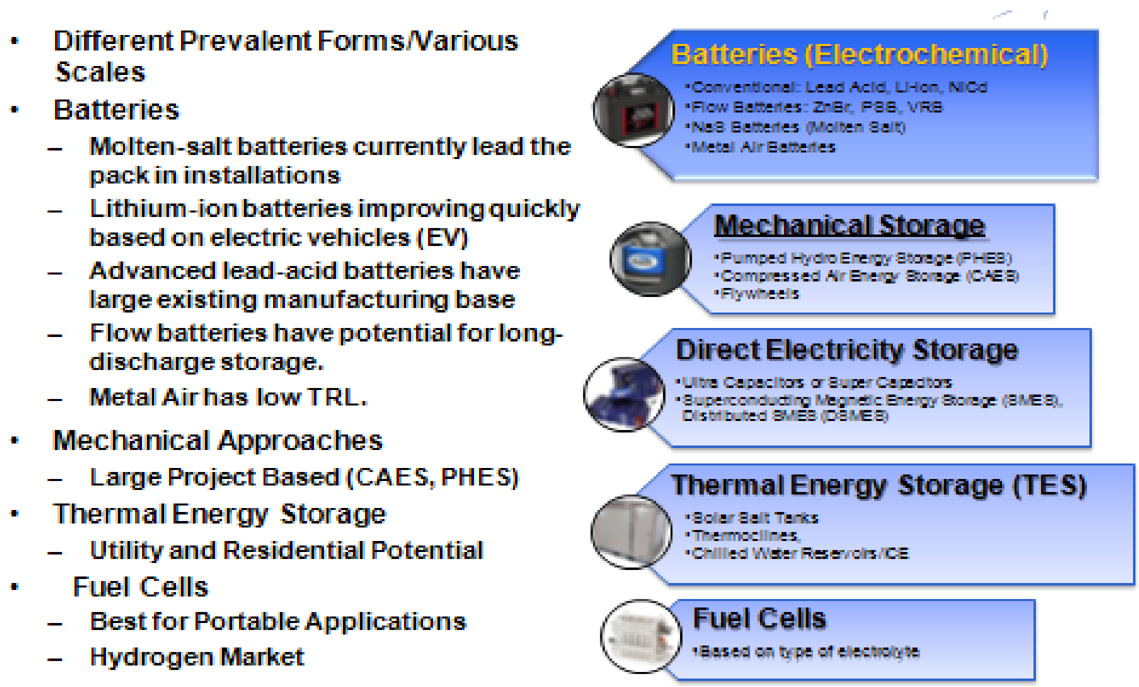

Figure 3-37. Energy Storage Technology Overview.

Understanding the difference between power and energy is required to assess the suitability of deploying storage technologies. Some approaches are best suited for energy applications (long duration power dispatch in hours) while others are best suited for power applications (dispatch duration from seconds to minutes). Figure 3-38 lists information regarding the uses of various energy/power storage alternatives.

Storage Technologies	Main Advantages (Relative)	Main Disadvantages (Relative)	Energy Application	Power Application
Pumped Hydro Storage	High Capacity, Low Cost	Special Site Requirements	●	
Compressed Air	High Capacity, Low Cost	Special Site Req'ts, Needs Gas Fuel	●	
Flow Batteries (PSB, VRB, ZnBr)	High Capacity, Independent Power & Energy Ratings	Low Energy Density	●	◐
Metal Air	Very High Energy Density	Electric Charging is Difficult	●	
NaS	High Power & Energy Densities, Efficiency	Production Cost, Safety Concerns (design addressed)	●	●
Li-ion	High Power & Energy Densities, High Efficiency	High Production Cost, Req'ts Spec Charging Circuit	○	●
Ni-Cd	High Power & Energy Densities, Efficiency		◐	●
Other Advanced Batteries	High Power & Energy Densities, High Efficiency	High Production Cost	○	●
Lead Acid	Low Capital Cost	Limited Cycle Life when deeply discharged	○	●
Flywheels	High Power	Low Energy Density	○	●
SMES, DMES	High Power	Low Energy Density, High Production Cost		●
E. C. Capacitors	Long Cycle Life, High Efficiency	Low Energy Density	◐	●

● Fully Capable & Reasonable
◐ Reasonable for this Application
○ Feasible but not quite practical or economical
Not feasible or economical

Source: Energy Storage Association http://www.electricitystorage.org/ESA/technologies/

Figure 3-38. Energy and Power Storage Technology Comparison. [50]

3.9.2 Large-Scale Storage Methods (Kinetic)

Traditional forms of energy storage include pumped hydro and compressed air. This form of storage is the most economic at utility scales envisioned for the Mid-Columbia region and improvements to these approaches will be discussed.

3.9.2.1 Pumped Hydro Energy Storage

PHES may be viable to provide energy storage capacity in the region; however, siting is critical because geography is important for this approach. The objective is to store hours or days of energy for dispatch when required.

PHES cost is cited in the *Sixth Northwest Conservation and Electric Power Plan* as follows: "Though $1,000/kilowatt of installed capacity is often quoted as a representative cost of pumped storage hydro, a review of available cost estimates suggests that $1,750 to $2,500/kilowatt is more representative of current construction cost."[51]

3.9.2.2 Compressed Air Energy Storage

Using CAES, the energy is generated by releasing compressed air through a natural gas-fired combustion turbine. According to the *Sixth Northwest Conservation and Electric Power Plan*,

[50] Source: U.S. Energy Information Administration.
[51] *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010, pp. 6-43.

"CAES technology has potential in the Northwest to improve the load factor of transmission used to deliver power from remotely located wind and solar generation, and for within-hour and hour-to-hour load-following and shaping services."[52] Traditional CAES requires underground caverns, although smaller scale approaches have been considered.

Even without caverns available in the Mid-Columbia region, aboveground CAES may be viable, where pressure vessels are used to store the compressed air. Electric Power Research Institute has sponsored research in one such project at the 15 MW scale.[53] Aboveground CAES is highly scalable allowing capacity built out in phases. There also is an economic advantage because tanks, vessels, and materials could be manufactured in the area.

A CAES system should consider regulation of the stored air temperature. Air compression for storage generates considerable heat. The air is warmer after compression. Decompression also requires heat to generate power through a turbine without harming the turbine blades. If the heat generated during compression can be stored and used again during decompression, CAES storage efficiency is improved considerably.

One company, SustainX,[54] offers aboveground CAES, does not require a gas turbine to use the decompressed air, and has recently claimed to manage the temperature. According to Greenbang:

> *"[The SustainX] patent will enable additional ways to use its compressed-*air *system with either hydraulics or a mechanical crankshaft. The company says the crankshaft design offers low frictional losses for better efficiency, and can also transfer large amounts of power, which will support the construction of megawatt-scale storage systems.*
>
> *One of the problems with compressed-air energy storage (CAES) is heat: when air is compressed to store energy, it heats up, and dissipated heat that's not recaptured means wasted energy and a loss of efficiency. SustainX claims its technology keeps air temperatures nearly constant (isothermal) during both compression and expansion, making it more efficient than other systems.*
>
> *The company also stores air in standard, off-the-shelf industrial gas cylinders above ground instead of in underground salt domes, as do the world's two existing CAES operations. That allows its system to be both scalable and transportable to wherever energy storage is needed."*[55]

The cost of a SustainX system is not known, however, this approach may offer an opportunity for CAES in the Mid-Columbia region.

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[52] *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010, pp. 6-42.
[53] See http://www.espcinc.com/library/15_MW_CAES_Project_with_Above_ground_Storage.pdf.
[54] See company website: http://www.sustainx.com/.
[55] "SustainX eyes compressed-air energy storage at megawatt-scale," http://www.greenbang.com/sustainx-eyes-compressed-air-energy-storage-at-megawatt-scale_20415.html.

3.9.3 Electric Storage Methods

3.9.3.1 Battery Storage

Batteries are the most common and mature energy storage technology in widespread use. Various types of batteries are available, with varying energy densities and performance characteristics. Electrochemical batteries can be classified into two major categories, namely flow batteries where the electrolyte is pumped for charging and discharging, and static batteries where the electrolyte is stationary and charging and discharging depends on the state of charge (SOC). Battery charging characteristics can be complex and nonlinear and almost all batteries exhibit degradation in performance if charging and discharging rate, frequency, and depth are not adequately managed. The most important metrics for a battery's performance are cycle life, energy/power density, self-discharge rate, efficiency, maximum allowable depth of discharge, and total cost per cycle. An overview of the cycle life, efficiency, cost, and other characteristics of various types of batteries used for energy storage is provided in Figure 3-39.

Battery type	Largest capacity (commercial unit)	Location & application	Comments
Lead acid (flooded type)	10 MW/40 MWh	California-Chino Load Leveling	$\eta = 72–78\%$, cost [d]50–150, life span 1000–2000 cycles at 70% depth of discharge, operating temperature −5 to 40 °C [a], 25 Wh/kg, self-discharge 2–5%/month, frequent maintenance to replace water lost in operation, heavy
Lead acid (valve regulated)	300 kW/580 KWh	Turn key system [b] Load Leveling	$\eta = 72–78\%$, cost [d]50–150, life span 200–300 cycles at 80% depth of discharge, operating temperature −5 to 40 °C [a], 30–50 Wh/kg, self-discharge 2–5%/month, less robust, negligible maintenance, more mobile, safe (compared to flooded type)
Nickel Cadmium (NiCd)	27 MW/6.75 MWh [c]	GVEA Alaska Control power supply Var compensation	$\eta = 72–78\%$, cost [d]200–600, life span 3000 cycles at 100% depth of discharge, operating temperature −40 to 50 °C, 45–80 Wh/kg, self-discharge 5–20%/month, high discharge rate, negligible maintenance, NiCd cells are poisonous and heavy
Sodium Sulphur (NaS)	9.6 MW/64 MWh	Tokyo Japan Load Leveling	$\eta = 89\%$ (at 325 °C), life span 2500 cycles at 100% depth of discharge, operating temperature 325 °C, 100 Wh/kg, no self-discharge, due to high operating temperature it has to be heated in stand-by mode and this reduces its overall η, have pulse power capability of over 6 times their rating for 30 s
Lithium ion			$\eta \approx 100\%$, cost [d]700–1000, life span 3000 cycle at 80% depth of discharge, operating temperature −30 to 60 °C, 90–190 Wh/kg, self-discharge 1%/month, high cost due to special packaging and internal over charge protection
Vanadium redox (VRB)	1.5 MW/1.5 MWh	Japan Voltage sag Peak load shaving	$\eta = 85\%$, cost [d]360–1000, Life span 10,000 cycles at 75% depth of discharge, operating temperature 0–40 °C, 30–50 Wh/kg, negligible self-discharge
Zinc Bromine	1 MW/4 MWh	Kyushu EPC	$\eta = 75\%$, cost [d]360–1000, operating temperature 0–40 °C, 70 Wh/kg, negligible self-discharge, low power, bulky, hazardous components
Metal air			$\eta = 50\%$, cost [d]50–200, Life span few 100 cycles, operating temperature −20 to 50 °C, 450–650 Wh/kg, negligible self-discharge, recharging is very difficult and inefficient, compact
Regenerative fuel cell (PSB)	15 MW/120 MWh (under development)	Innogy's Little Barford station UK	$\eta = 75\%$, cost [d]360–1000, operating temperature 0–40 °C, negligible self-discharge

[a] Operating at higher temperature will reduce the life and operating at lower temperature will reduce the efficiency.
[b] At Milwauke, Wisconsin.
[c] Provides 10 MVar even when the battery is not discharging.
[d] Capital cost in Euro/kWh.

Figure 3-39. Various Battery Technologies.

Deep-cycle lead-acid batteries are currently the most common and mature energy storage technology for solar applications due to their low cost per cycle and per kWh, low self discharge rate, and the fact that their low energy density is not a concern in stationary power plant applications where large storage spaces are available. They are unlikely to be superseded in the near future as the primary energy storage technology for large-scale applications. Their relatively poor cycle life may be improved via the use of a battery-supercapacitor hybrid (discussed later in this section).

Nickel-Cadmium (Ni-Cd) batteries also are well suited to remote area PV applications because they may be cycled more deeply than lead-acid batteries and have a much longer cycle life and therefore operational lifetime. Li-Ion batteries have also usurped NiCad in recent times due to electric vehicle applications. For utility-scale applications, large format prismatic Li-Ion batteries and modules are available from A123, Dow Kokam, International Battery, LG Chem, Electrovaya, and other suppliers. Different Li-Ion chemistries (variations on the basic Lithium Iron Phosphate chemistries) are available from different suppliers. More exotic types of batteries such as silver-zinc tend to be cost prohibitive for large-scale applications due to the high costs of manufacturing materials or processes. These historically have been used in space and underwater applications where high costs are overridden by excellent power and energy density.

The maximum achievable rate of discharge as a function of battery capacity (or C-rate) also is a limiting factor in battery performance. The faster the charge is drawn from a battery, the less efficiently the battery performs. Lead-acid batteries generally achieve their best discharge efficiency at a C-rate of 0.05C, meaning a maximum of 0.05A can be drawn from a 1Ah battery at the nominal voltage without causing an efficiency loss. If charge is drawn at a higher rate, say 1C, the efficiency (and therefore apparent capacity) declines dramatically. As a result of this, the relationship between discharge rate and total discharge time is nonlinear, meaning over-sizing of lead-acid battery banks is often necessary to allow high-power delivery.

Battery SOC is a complex function of cell voltage, operating temperature, and battery use history, and therefore, may be difficult to measure. Sophisticated circuitry in the form of charge controllers is usually necessary to design an effective system and prevent excess wear on the batteries.

3.9.3.2 Flow Batteries

Flow batteries have been deployed in energy storage pilot projects, and are available in small scales. ***Redox flow battery*** technology is a widely used term to describe the approach. Redox flow batteries comprise a subset of the large number of technologies available.

Redox is the abbreviation for reduction-oxidation reaction; the redox flow battery is based on the redox reaction between the two electrolytes in the system. These are sometimes referred to as the anolyte and catholyte. These reactions include all chemical processes in which atoms have their oxidation number changed. Within a redox flow cell, the two electrolytes are separated by a semi-permeable membrane that allows ion flow, but prevents mixing of the liquid electrolytes. Electrical contact is made through inert conductors inserted in the liquids. As the ions traverse the membrane, an electrical current is induced in the conductors.

Flow batteries have the following general characteristics:

- Rather than store energy in both the electrolyte and the electrode, energy is stored and released using a reversible reaction between two electrolyte solutions separated by an ion-permeable membrane
- Both electrolytes are stored separately in bulk storage tanks

- The size of the tanks defines the energy capacity of the system
- The number of cells or stacks within the flow battery defines the power flow rating
- Chemical energy is directly converted to electricity.

The following redox battery types are commercially deployable:

- VRB
- ZnBr
- Iron Chromium (FeCr).

Zinc Chloride (ZnCl) and Sodium Bromine or PolySulfide Bromide (PSB) flow battery technologies were examined but judged to have lower readiness levels, and are therefore excluded in any near-term assessment. PSB is a demonstration only system using Regenesys technology, and VRB Power (now Prudent Energy) bought the intellectual property rights. ZnBr flow batteries have three major suppliers and have been deployed to a greater degree than VRB. There is a new VRB supplier in Ohio.

Sodium Sulfur (NaS) batteries also could be considered a flow battery, but were not because the difference of the way the electrolytes are separated within the stack. In NaS batteries, liquid (molten) sulfur at the positive electrode and liquid (molten) sodium at the negative electrode are separated by a solid beta alumina ceramic electrolyte. This is a different architecture than the other candidates which use a membrane for separation. However, there is only one supplier for this technology (NGK Insulators), therefore availability is limited. According to EIA, only NaS can perform both Power and Energy functions.

Besides ZnCl and PSB flow batteries, one other class of flow battery deserves consideration. Metal air ionic liquid (MAIL) batteries are not ready for deployment because large-scale storage is not currently viable, electrical recharging is difficult and inefficient, rechargeable metal air batteries under development have an efficiency of 50 percent, and they have an estimated lifetime of only a few hundred lifecycles. The promise of MAIL batteries is an order of magnitude increase in energy density, saving considerable balance of system costs. Although MAIL batteries may be described as a type of flow battery, current candidates should be limited to the redox type (VRB, ZnBr, and FeCr) for now.

According to the *Sixth Northwest Conservation and Electric Power Plan*, capital costs (for flow batteries) are relatively high. One United States demonstration plant of 250 kW capacity and 2 MWhs of storage is reported to have cost $4,000/kW.[56] In July of 2011, a ZnBr flow battery supplier stated an equipment price of $400/kWh in a public forum.

3.9.3.3 Flywheels

Flywheels store mechanical energy using a spinning rotor with a large moment of inertia, which later can be converted into electrical energy via an integrated motor/generator. In comparison to batteries, they have no toxic chemical components, have a very high cycle life and deep discharge capability, high energy density, and have a charge level that is simply a function of the rotor speed. However, there are safety issues related to their fast-moving parts, particularly with

[56] *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010, pp. 6-42.

respect to containment in the case of catastrophic failure. There are only a few examples of this technology being successfully deployed.

Flywheels can help power quality regulation, but are not suited to long-term energy storage due to their large standby losses ("Power System Technology," [Coppez et al. 2010]); therefore, the flywheel target application is best for voltage regulation or frequency management.

3.9.3.4 Supercapacitors

Electric double-layer capacitors operate differently from batteries in that they store the charge electrically, not chemically. This results in very high power density as well as very fast charge and discharge rates when compared with batteries. The operational lifetime of a supercapacitor is significantly higher than that of a battery due to their far superior cycle life (tolerating hundreds of thousands of cycles to failure). A comparison of batteries and supercapacitors is shown in Table 3-11.

Table 3-11. Battery versus Ultracapacitor Performance.

	Lead-Acid Battery	Ultracapacitor
Specific Energy Density (Wh/kg)	10 - 100	1 - 10
Specific Power Density (W/kg)	<1,000	<10,000
Cycle Life	1,000	>500,000
Charge/Discharge Efficiency	70 – 85%	85 – 98%
Fast Charge Time	1 – 5 hours	0.3 – 30 seconds
Discharge Time	0.3 – 3 hours	0.3 – 30 seconds

However, supercapacitors suffer from high self-discharge rates, low overall energy density, and prohibitive costs, all of which are to their detriment in bulk energy storage applications.
At present, they have found successful application in specific areas of clean energy storage, such as providing short, high-power bursts for wind turbine pitch control systems.

3.9.3.5 Battery-Supercapacitor Hybrids

Battery-supercapacitor hybrids, dubbed supercapatteries, combine the high energy density of traditional chemical batteries and the high power density of supercapacitors. When a large load is suddenly applied to a supercapattery, the supercapacitors provide the peak power, protecting the batteries from damaging load spikes. The batteries provide the base load due to their superior bulk energy storage properties. This type of system reduces the frequency of charge-discharge cycles of the batteries and allows them to remain at a higher SOC, increasing their usable lifetime. Usage of supercapatteries can be beneficial in periodic, pulsed-load applications such as radar.

Suitable control algorithms and associated circuitry such as battery and supercapacitor charge controllers are required to realize such a hybrid energy storage system. Detailed planning in the system sizing and optimization phase can significantly increase the effectiveness of a hybrid storage system increasing overall system efficiency and decreasing lifetime costs.

3.9.4 Thermal Storage for Solar Thermal (Concentrated Solar Power) Methods

The various thermal energy storage (TES) concepts can be classified as follows:

- Direct (heat transfer medium is the same as the heat storage medium) or steam accumulator
  - Two tank oil storage
  - Graphite block
  - Dual media (the heat transfer medium is different than the heat storage medium).
- Liquid heat transfer fluid (e.g., thermal oil) transferring heat to molten salts for sensible heat storage
  - Liquid heat transfer fluid (e.g., thermal oil or molten salts) transferring to solid media for sensible heat storage (e.g., concrete or other media).
  - Liquid heat transfer fluid (e.g., thermal oil or molten salts) transferring latent heat to phase change materials.

At utility scale, two tank indirect molten salt has been deployed at 50 MW in Spain (Andasol and other plants), extending dispatch of solar thermal plants. Improvements to the molten salt TES approaches are still being tested. Molten salt TES is applicable primarily to intermittent thermal systems like CSP.

3.9.5 Energy Storage

Electric: Deep-cycle and lead-acid are the most common and mature energy storage technology for solar applications, have a low-cost per cycle and per kWh (see Figure 3-39), and low-self discharge rates; however, Li-Ion batteries are becoming available for power applications, and Flow Batteries, with less cycling limitations, are available for utility-scale energy applications. It is probable that using supercapacitors in front of the batteries would significantly increase the life of the batteries and would be an interesting proposition.

Thermal: Most common two tank indirect molten salt at the utility scale, and at small scale, the most practical form of TES is stored hot or chilled water.

3.9.6 Storage Performance Economics

As previously mentioned, the power and energy storage value propsition is a complex undertaking. Storage economics key parameters must be defined to assess the technology and manage performance. The following parameters are key to assess performance:

Profit/Cost:

- Actual Revenue (Service Specific)
- Planned Revenue (Service Specific)
- Cost Per Cycle
- Cost Per kWh
- (Degradation Costs Included).

Performance:

- Input Power (Storage Assets)
- Output Power (Generation and Storage Assets)
- Efficiency (DC and End to End)
- Rate of Charge/Discharge/Time to Charge/Discharge
- SOC (Measured/Calculated) Minimum, Preferred Minimum
- Cycles Remaining
- Voltage
- Temperature
- Self-Discharge Rate (Batteries)
- Capacity
- Availability
- Solar Resource (W/m^2)
- Wind Resource (miles per hour).

Scheduling:

- Scheduled Production Times/Capacity
- Charge/Discharge Times
- Maintenance Times (Scheduled and Unplanned)
- Cycles Scheduled.

3.9.7 Power and Energy Storage Integration

Storage can be deployed at a small scale and distributed close to the clean energy generation asset, or the grid can be used to interconnect the storage with the renewable asset. From a utility perspective, grid connected storage provides ancillary services and spinning reserves. Various approaches to integrate storage are depicted in Figure 3-40.

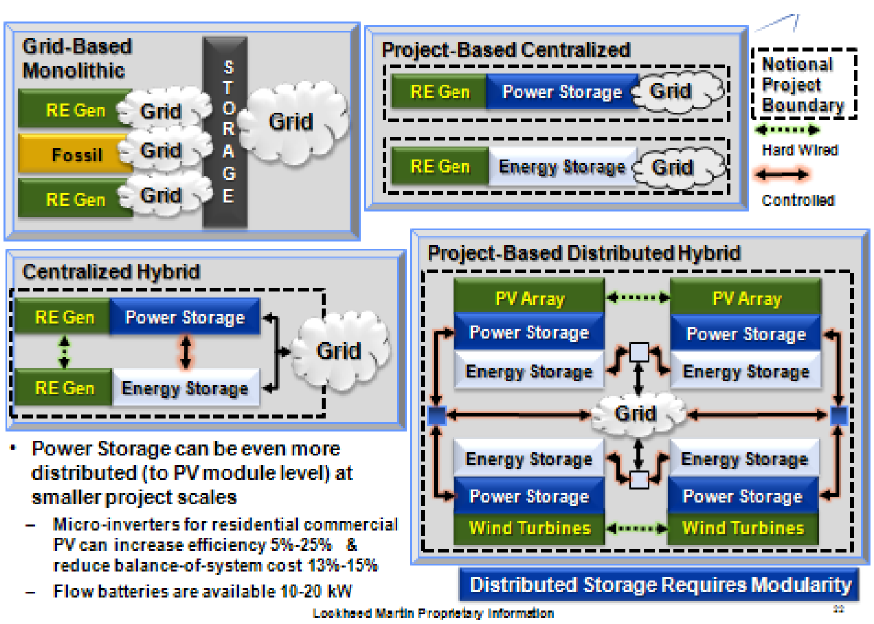

Figure 3-40. Storage Integration Approaches.

Deployment of cost-effective storage is very situation and site specific; however, the Mid-Columbia region supports both utility-scale and small-scale deployment of both power and energy storage.

3.9.8 Conclusions and Recommendations

Conditions for the deployment of power and energy storage in the Mid-Columbia region have improved since the original study was performed in 2008. There is more past precedent for construction of utility-scale storage and decentralized small-scale storage projects. The business proposition for power and energy storage is extremely complex. Overall:

- The *Sixth Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, February 2010 considered opportunities for PHES, CAES and NaS.
- There are promises of additional financial incentives for storage based on its relationship to clean energy generated electricity.
- Policy is evolving (e.g., California Assembly Bill No. 2514).
- Flow Batteries and Li-Ion batteries have been deployed in large-scale pilot projects, and these technologies are being commercialized; however, there are still cost considerations.
- Equipment costs for power and energy storage are comparatively expensive; therefore, each supplier must be evaluated.
- New developments permit more flexible deployment of large-scale forms (aboveground CAES and piston/shaft-based PHES).

Further evaluation of the following is proposed:

- Determine power and energy storage requirements and work with utilities and grid managers to establish feasibility/revenue streams
- Assess potential sites considering interconnections (grid conditions) and geographic attributes (e.g., for PHES, proximity to water, construction requirements)
- Perform tradeoffs of various approaches and continue to monitor developments
- Establish a PPA framework between all parties involved to encourage third-party developers to consider large-scale storage projects. This would encourage project feasibility efforts to be made by developers.

Measures to encourage deployment of storage pilot projects in the Mid-Columbia region are justified.

3.10 ELECTRICITY VERSUS FUELS

The value of liquid fuels made from wheat straw is about twice that of green electricity from the same fuel. Capital costs are about twice as great. The spread between straw and natural gas and the electricty they can produce is small so it is currently

Operating Profit Potential

- Straw biomass to jet fuel produces a significant operating profit – natural gas provides a backup.
- Straw biomass to electrical power via fermentation processes produces a reasonable operation profit.
- Municipal solid waste to electrical power produces a significant operating profit.

impossible to make a reasonable payback on a new plant with proven technology. Existing plants with capital paid off are just barely able to operate on woody biomass, which is a less expensive fuel than straw. Currently, the cost of biomass and natural gas are all about the same per Btu of usable combustion heat. A natural gas combined cycle plant can achieve a 53 percent conversion efficiency. The 30.7 percent efficiency of a steam plant for biomass is offset by the higher green power price ($65/MWh) compared to the $36/MWh current electric power price in the region.

If a plant that ferments straw to methane were built, the methane could be supplied to a combined cycle plant. The plant would have the capital and operating costs of a 75 MW natural gas plant from the green power revenues of the straw to electricity plant. This plant would have a reasonably good payback; however, the cost and operating characteristics of the straw fermentation process need to be better understood through the operation of a pilot-scale plant. The economics of a fermentation plant could be proven by building a demonstration plant that initially supplies its biogas into the pipeline to be burned at a power plant. Figure 3-41 shows the differences in capital costs between a MSW boiler, a GTL plant, and a straw biogas fired combined-cycle power plant.

3.11 SEQUENCING

There are significant differences in the employment costs between the various plants shown in Figure 3-41. Most of this report has focused on demonstration-scale plants of 75 MW or an equivalent liquid fuel production. None of these plants have a payback in less than 10 years; however, local resources are capable of supporting a much larger plant. There is enough regional wheat straw to make 308 Mgal/year of liquid fuel or 1575 MW of electricity. There is enough regional MSW to make 342 MW. As the plants increase in size and capacity, the capital costs do not rise linearly, but rather follow the 0.6 exponential factor relationship. Based on larger plant size, a payback of less than 10 years could be achieved; however, development of smaller demonstration plants is desired, with increases in size and capacity over time.

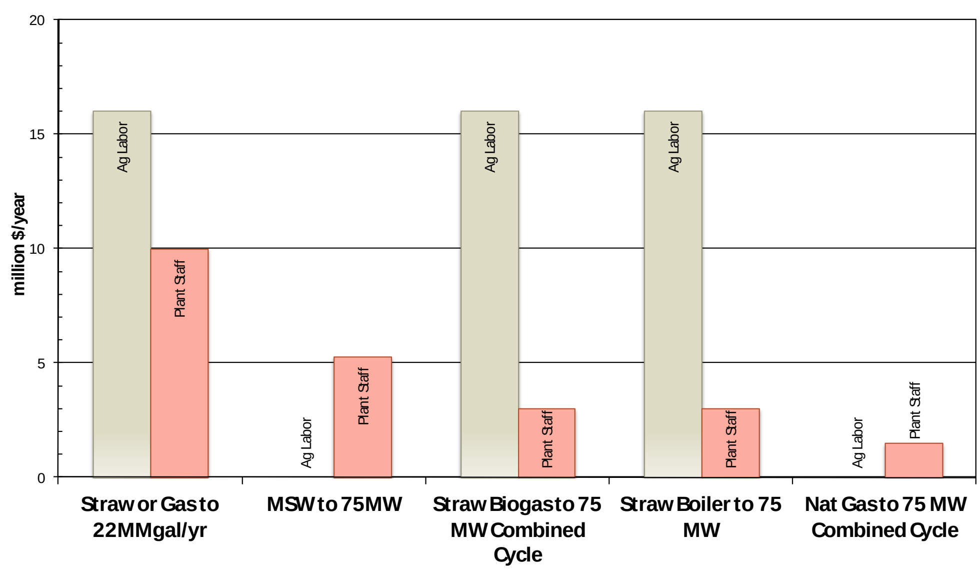

Figure 3-41. Demonstration Plant Labor Costs.

4.0 SUMMARY AND PATH FORWARD

This study has shown the presence of necessary resources in the Mid-Columbia region to meet clean energy needs of federal agencies in the region, and also to support the development of a significant clean energy industrial base. This study has highlighted several business development conditions necessary to support creation of that industrial base. Finally, it has revealed several separate, but mutually supporting, value propositions to be considered by civic authorities, potential developers, and investors. These value propositions are not recommended courses of action. Instead, they present a set of existence proofs to show a path forward for decision making, planning, and for due diligence processes required for future development.

4.1 RESOURCES

4.1.1 Biomass

A review of biomass resources available in the Mid-Columbia region has shown a strong base of agricultural waste biomass available for exploitation. Continuous production of more than 50 MW or 75 Mgal of diesel fuel per year can be supported. This biomass resource, principally in the form of wheat straw, can be obtained strictly as a byproduct of food production. Thus, biomass-based energy production would have no impact on food supply, land or water resources, and in fact could have a positive effect on the agricultural economy of the region. Other biomass resources available include waste from alfalfa seed production, corn harvesting, and winery wastes; however, wheat straw is the dominant source and focus of the study. Two other sources, woody biomass and MSW, also were considered and show much promise; however, most of those resources are generated on the western side of the state and thus would suffer due to the cost of transportation needed to bring it to a centrally-located processing site in the region. Technologies needed for energy or fuel from waste biomass exists and appears to provide a path for development that will work functionally and economically.

4.1.2 Solar and Geothermal

Both of these renewable energy sources have been touted as very promising for meeting the region’s renewable energy needs; however, both sources have issues that may make them less promising. Solar is adversely affected by a less-than-ideal regional solar index (notably during winter months), although this is counterbalanced somewhat by the low cost of new PV cells. The primary use of solar energy in the region could be direct heat for warming water or providing process heat as opposed to generating electricity, which would be particularly useful in site-specific use installations.

Geothermal sub-surface heat is a very promising resource in broad areas of the Pacific Northwest, but high-temperature rock in the local Mid-Columbia region is only found at very great depths, so the economics of geothermal power in the area are not outstanding. Other uses for geothermal energy, principally from shallow resources, could be very useful for improving efficiency of heating and air conditioning systems, although care must be taken to avoid interaction with contaminated groundwater.

4.1.3 Natural Gas

Although natural gas is technically a fossil fuel, its low carbon content and low cost will make it an important addition to energy sources available for the Mid-Columbia region. Projected GHG savings made possible by the installation of natural gas services for industrial purposes in the region are estimated at more than 3 million tons of GHG emissions and approximately $800 million across the life of the cleanup effort. Additional cost savings are possible if gas is applied in transportation and other ancillary applications.

Just as important is the potential for using natural gas as an enabler for clean energy industry development. Developers of clean energy infrastructure need to be reassured of a reasonable probability of profitable return on investment in a predictable time. Natural gas could be used as an enabler for bio-sourced gas infrastructure development, either in electricity generation or liquid fuels production. As an example, a natural gas powered electricity peaking plant could be a practical investment for a commercial developer, making power to balance wind generation for integration onto the grid, meeting short-term needs of grid managers, and even supplying power for extended periods during low river-flow and wind conditions. If specified correctly, and with appropriate off-taker agreements in place, that same power plant could operate on gas produced from biomass when infrastructure is in place to make the gas. This would ensure bio-developers of a reliable off-taker when they have developed a significant capacity for production, and the generator developers will have an assured reliable return in the near term using natural gas. Similarly, a natural gas GTL plant using existing technology could be an off-taker for gas from a biomass processing plant as well. Either or both of these arrangements would provide significant risk mitigation for potential investors in advanced biomass processing infrastructure.

4.1.4 Water Rights

Essentially all industrial processes, including electricity generation, fuel production, and biomass processing, use significant amounts of water. Water rights are a major issue in virtually all of North America, and Southeastern Washington State is no exception. The Federal Government has reserved water rights established for defense purposes in the region; however, it is not expected that those rights would be available for clean energy development. For environmental reasons, groundwater (i.e., water pumped from wells) from the local area is not likely to be a significant resource. Use of water from the Columbia River is tightly controlled; however, the communities in the region have secured long-term rights for local development. Water resources for development will have to be identified early, and local authorities should be prepared to render assistance to developers to facilitate development of business arrangements leading to major investment. Pre-existing arrangements to meet green energy development water needs would be a significant asset for the community in a search for potential developers.

4.1.5 Infrastructure

The Mid-Columbia region provides strong support for industrial development. Transportation infrastructure is robust, offering a network of major and minor highways, railroads including spurs and sidings, and navigable river channels stretching from the Pacific Ocean far inland east and north of the Tri-Cities area, as well as natural resources (large amounts of land) and a supportive host community. The region lies at the center of the BPA system for power transmission and supply. The regional population possesses a highly skilled workforce for high technology work and a strong tradition of agriculture, providing workforce capacity to support virtually any development supported by markets and resources.

4.2 VALUE PROPOSITIONS

Several clean energy business cases were evaluated in this study to provide reasonable assurance that conditions in the Mid-Columbia region will support clean energy project development. Several of these concepts have the potential to serve as value propositions to demonstrate possible paths forward.

4.2.1 Exploitation of Natural Gas to Enable Creation of Clean Energy

The availability of natural gas in the Mid-Columbia region provides major cost savings and reductions in GHGs in the local region. It will also provide an opportunity to support future business development for clean energy in the local area. Local stakeholders can encourage development of natural gas-based projects that, while independent of technology and process development of clean energy sources, can act as assured off-takers for those renewable sources when those sources are ready for commercial production.

4.2.1.1 Power

The Northwest Power and Conservation Council states the *Sixth Northwest Conservation and Electric Power Plan* has identified a need for additional generation capacity for the region, for peaking capacity, to help efficiently integrate wind power onto the grid, and to add sustained capacity to the system in high demand periods. This demand tends to push solutions toward simple turbine installations that do not use combined-cycle thermal adjuncts, due to their ease of operation and low capital cost. A natural gas-fueled peaking plant, using efficient and responsive gas turbine or diesel power, also could be specified to be able to use biomass sourced gas produced in a new facility in the region, using regional biomass from agricultural waste. A natural gas-fueled peaking plant would be a practical business proposition with or without bio-derived gas, and thus would have lower risk for an investor than a plant that was a specialized design for bio-gas only. At the same time, it would provide an assured off-taker for a biomass gas plant, improving the potential for developing a biomass industry in the area. A natural gas-fueled electric generating plant with a defined path to bio-derived gas use would be a good candidate for development.

4.2.1.2 Fuel

A similar business development case exists for a natural-gas supplied GTL fuels installation. Due to the high cost of fuels and the relatively low cost of electricity available in the Pacific Northwest, liquid fuel production may be a better fit than electrical generation economically. Such technology is relatively mature, with some commercial-scale plants in production. A GTL plant, with a long-term allowance to use bio-sourced gas to supplement or replace natural gas when economic conditions encourage it, is a business case worth pursuing for the region.

4.2.2 Biomass

A survey of the Mid-Columbia region has revealed that wheat straw is a potentially rich biomass resource produced as waste by wheat growers. Other sources, such as alfalfa straw and wine industry waste, also exist in smaller amounts. New technologies for processing the agricultural waste into gas for direct use or further processing into liquid fuels are developing rapidly, with the potential for reasonable economic return. These new technologies need to be stood up in a progressive fashion, proving returns and mitigating risk of development as they are industrialized and grow in capacity. The existence of local off-takers, including a gas generating plant and/or a GTL plant, would serve as an important inducement for investors and developers.

4.2.3 Other High-End Products

The biomass-derived gas can also be processed into other important and economically rewarding products such as industrial solvents, adhesives, and plastics. Financial return on these products is often much higher than for energy, and these non-energy industries may become attractive development candidates. While much of our attention is focused on energy development, this industrial chemical path should not be discounted in master planning.

These concepts and their interrelation are laid out in Figure 4-1. The combination of these separate paths, economically independent but mutually supporting, provide a smart path for local stakeholders to create and follow to build a green industrial base in the Mid-Columbia region.

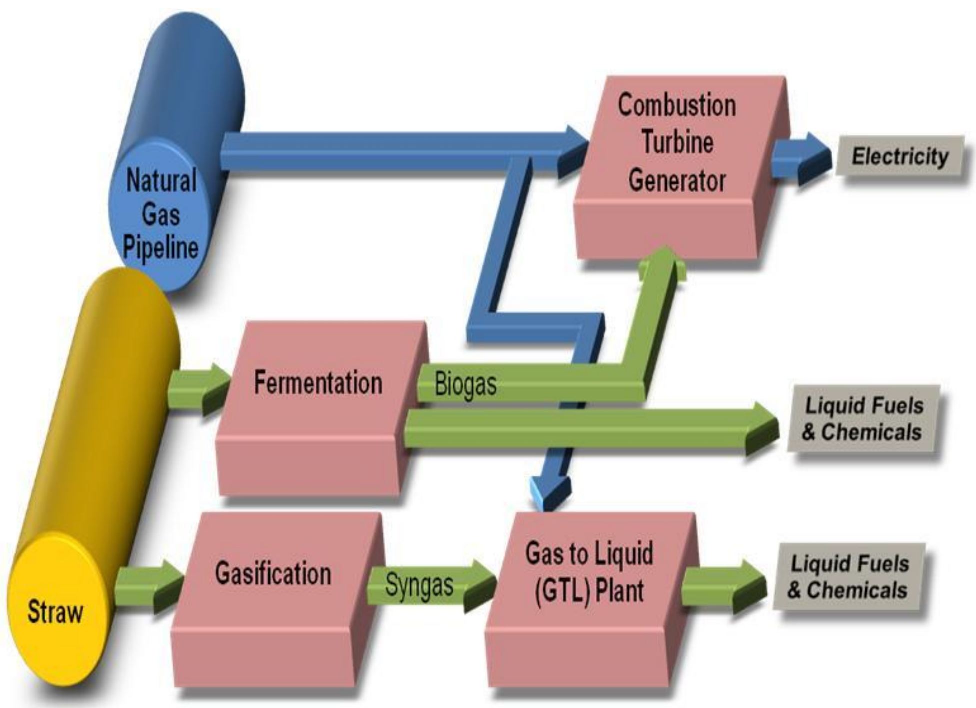

Figure 4-1. Integration of Clean Energy Generation.

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APPENDIX A

TECHNICAL IDEAS WORTH FURTHER CONSIDERATION

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APPENDIX A

TECHNICAL IDEAS WORTH FURTHER CONSIDERATION

A1.0 PURPOSE

The intent of this appendix is to address items that were not specifically part of the scope but that were considered to be worth documenting. The team discovered several areas, listed below, that were considered to be of interest despite the fact that they were not within the scope of the study. Rather than lose this data, the decision was made to document the team findings in this appendix.

It should be noted that items are documented to the level that data exists rather than to any kind of standard. That is, information is provided in this appendix as it was available to the team and is not intended to be as well documented as the other areas within the study report.

In addition, a few of the items included in this appendix are technologies that could potentially use the excess power available in the region (e.g., wind). While these technologies were not fully investigated, the information that was gathered was considered to be of particular interest. Sections A1.1.1 through A1.1.3 are considered to be in this category.

A1.1 ELECTROLYSIS OF WATER

A1.1.1 Hydrogen Production from Renewable Energy Resources

Hydrogen provides the connecting point between clean electricity production, transportation, and stationary and portable energy needs. When the electricity from solar PVs, wind, geothermal, ocean, and hydro technologies is used to produce and store hydrogen, the renewable source becomes more valuable and can meet a variety of needs. In transportation applications, hydrogen provides a way to convert renewable resources to fuel for vehicles. Renewably produced hydrogen for transportation fuel is one of the most popular hydrogen economy goals, as it can be domestically produced and emissions-free. Renewable energy resources often produce power intermittently (e.g., only when the sun is out or the wind is blowing), so hydrogen can increase stationary power reliability when used as an electricity storage medium. Hydrogen, renewably produced during off-peak periods and stored, can provide constant power using fuel cells or engines when the renewable source is not available.

To have a highly effective and efficient renewable-hydrogen system, the hydrogen should be used at choice times. At the time when renewable resources are available (e.g., the sun is shining), and electricity is needed, the electricity should be used directly. To meet an even higher electricity demand, energy can be supplied directly from renewable sources as well as from the hydrogen stores. As demand decreases, extra electricity from renewable sources can be converted and stored as hydrogen. This entire portfolio of options is what makes renewable-hydrogen systems effective in providing flexible, reliable energy in whichever form is needed most. There are few other options today for electricity storage at a large scale. Batteries are not practical and are too costly, and pumped water systems and compressed air energy storage systems are only implementable in limited geographical areas.

In the near term, hydrogen produced in the United States may be from fossil fuels, but industry and governments have their sights on increasing hydrogen production from renewable energy resources. Hydrogen can help clean energy electricity technologies mature and become more cost competitive. In the meantime, hydrogen production from fossil fuels can use low cost, existing infrastructure along with emerging methods to capture and store GHG emissions to provide hydrogen while minimizing environmental impact.

Renewable energy resources are an emissions-free way to produce hydrogen by electrolysis, and conversely, hydrogen offers a way for renewable sources to generate transportation fuel and reliable power. The versatility of clean energy technologies allows them to be adapted to meet diverse energy needs. Though costs for some clean energy technologies are higher than traditional generation sources, technology advancements and increased market penetration are reducing prices. Additionally, the environmental benefits help to compensate for the higher costs. When taken as a whole, the future conjunction of hydrogen and clean energy technology is a promising one.

A1.1.2 Hydrogen Production through Electrolysis

The main commercial advantages of hydrogen production by electrolysis are its scalability and the emission-free production of hydrogen (when produced via clean energy). Conventional electrolysis is the most common method used to produce renewable hydrogen. Electrolysis involves the separation of water into hydrogen and oxygen, using an electric current. Although some electrolyzers use chemicals or intense heat to help the separation, conventional electrolysis uses no chemicals and works at room temperature.

Electrolysis separates water into its constituent elements, hydrogen and oxygen, by charging water with an electrical current. The charge, coming from two poles in the water, breaks the chemical bond between the hydrogen and oxygen and splits apart the atomic components, creating oppositely charged particles (Figure A-1). Because opposite charges attract, the negative pole (cathode) attracts the positive particle (with the hydrogen molecules), and the positive pole (anode) attracts the negative particle (with the oxygen molecules). As the particles reach the poles, the hydrogen and oxygen gases rise and are collected separately. (It takes about 53 kWh to produce 1 kg of hydrogen assuming a 75 percent efficient electrolyzer).

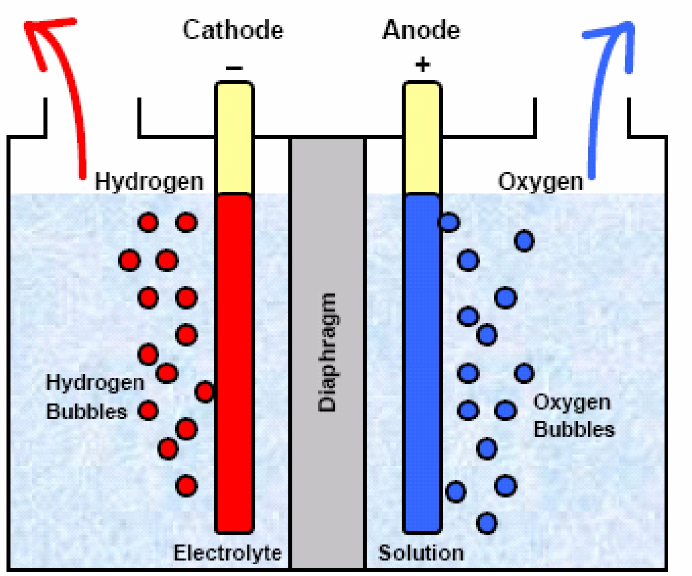

Figure A-1. Diagram Showing the Process of Conventional Electrolysis.

A1.1.3 Types of Electrolysis

Polymer Electrolyte Membrane Electrolyzer: In a polymer electrolyte membrane (PEM) electrolyzer, the electrolyte is a solid specialty plastic material. Water reacts at the anode to form oxygen and positively charged hydrogen ions (protons). The electrons flow through an external circuit and the hydrogen ions selectively move across the PEM to the cathode. At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas.

$$\text{Anode Reaction: } 2H_2O \rightarrow O_2 + 4H+ + 4e-$$

$$\text{Cathode Reaction: } 4H+ + 4e- \rightarrow 2H_2$$

Alkaline Electrolyzers: Alkaline electrolyzers are similar to PEM electrolyzers but use an alkaline solution (of sodium or potassium hydroxide) that acts as the electrolyte. These electrolyzers have been commercially available for many years.

Solid Oxide Electrolyzers: Solid oxide electrolyzers, which use a solid ceramic material as the electrolyte that selectively transmits negatively charged oxygen ions at elevated temperatures, generate hydrogen in a slightly different way. Water at the cathode combines with electrons from the external circuit to form hydrogen gas and negatively charged oxygen ions. The oxygen ions pass through the membrane and react at the anode to form oxygen gas and give up the electrons to the external circuit. Solid oxide electrolyzers must operate at temperatures high enough for the solid oxide membranes to function properly (about 500°C to 800°C, compared to PEM electrolyzers, which operate at 80°C to 100°C, and alkaline electrolyzers, which operate at 100°C to 150°C). The solid oxide electrolyzers can effectively use heat available at these elevated temperatures (from various sources, including nuclear energy) to decrease the amount of electrical energy needed to produce hydrogen from water.

A1.1.4 Advantages of Electrolysis

1. Potential for synergy with clean energy power generation - For example, though the cost of wind power has continued to drop, the inherent variability of wind is an impediment to the effective use of wind power. Hydrogen production via electrolysis may offer opportunities for synergy with variable power generation, which is characteristic of some clean energy technologies. Hydrogen fuel and electric power generation could be integrated at a wind farm, allowing flexibility to shift production to best match resource availability with system operational needs and market factors.
2. No GHG emissions - Hydrogen produced via electrolysis can result in zero or near-zero GHG emissions, depending on the source of the electricity used (emissions resulting from electricity generation must be considered when evaluating the environmental benefits of electrolytic hydrogen production technologies). Nuclear high-temperature electrolysis and renewable electrolysis, using renewable sources of electricity such as wind turbines, will result in near-zero GHG emissions.

A1.1.5 Barriers to Hydrogen Production through Electrolysis

There are challenges to setting up mainstream electrolyzer use for hydrogen production, primarily high capital costs and the cost of electricity. For example, PV electricity today costs approximately $.30/kWh, perhaps 10 times what is needed to make electrolysis cost competitive, and the cost of electrolyzers themselves must be significantly reduced to enable large-scale implementation. Many of the clean energy technologies have siting, social, or environmental concerns which also must be overcome; however, all these barriers are being addressed aggressively by government and industry, and it is worth considering whether the benefits warrant greater investment today.

Today's electricity grid is not ideal to provide the electricity required for electrolysis because of the GHG emissions and energy-intensive nature of the electricity generation technologies used. Electricity generation using clean or nuclear energy technologies, separate from the grid, is a possible option for hydrogen production via electrolysis.

DOE and others continue efforts to bring down the cost of clean energy-based electricity production and develop more efficient coal-based electricity production with carbon sequestration. Wind-based electricity production, for example, is growing rapidly in the United States and globally.

A1.1.6 Ongoing Research Focus

- Reducing the capital cost of the electrolyzer and improving energy efficiency.
- Integrating compression into the electrolyzer and avoiding the cost of a separate compressor needed to increase pressure for hydrogen storage.

A1.2 NIGHTTIME GENERATION OF OXYGEN

An investigation was made into the possibility of creating oxygen at night to take advantage of the excess power available. It was estimated that about 182 tons/day of oxygen of 98 percent purity at 300 psig would be required to enable plant operations. Approximately two-thirds of the oxygen would be used for reforming natural gas and the remaining one-third would be used for pre-treating biomass.

According to experts from Universal Industrial Gases, Inc., the power consumption required for a plant of this size would be about 3.5 MW to produce the oxygen needed cryogenically. As a point of comparison, it is estimated that 42 MW would be needed to produce oxygen through electrolysis. Using the current cost differential between night and day electrical rates it would not be cost effective to use this much power to produce oxygen at night. In addition, it is believed that storing 91 tons of oxygen under pressure would be completely impractical.

The investigation revealed another possible option. The liquefied co-products, nitrogen and argon might be made profitably if the liquefaction portion of the plant were run at night. In order to make this determination, the power required for liquefaction, which is believed to be no greater than the 3.5 MW required for the process described above, and the value of the liquid nitrogen that would be produced would need to be assessed. The economics of this process are based on the local market for the products. The Mid-Columbia region has a very low cost of power, which makes plant economics for plant operation more desirable; however, transportation costs impact the economic viability of this process. In summary, it is expected that the project would depend on the market within about 500 miles of the plant.

A1.3 AMMONIA/HYDROGEN HUBS

The following information was provided from the Executive Summary of the *Preliminary Feasibility Study of Hydrogen Hubs – An Energy Storage Device Using Anhydrous Ammonia as a Storage Medium* (Michie et al. 2010).

In June 2009, the Northwest Hydrogen Alliance, Inc. (NWHA), an Oregon non-profit entity created in 2002 to promote a hydrogen economy in the Pacific Northwest, received funding from a consortium of northwest electric power organizations to conduct a preliminary feasibility study of Hydrogen Hubs. A "Hydrogen Hub" is a term NWHA uses to describe an energy storage concept using anhydrous ammonia as the energy storage medium. The concept entails using electric power to electrolyze water to produce hydrogen. Nitrogen from the atmosphere is then mixed with hydrogen in a pressure tank that is heated with an iron catalyst to produce anhydrous ammonia. Anhydrous ammonia can be stored at modest pressures in a storage tank similar to that used to store propane, although modified to accommodate ammonia. The process is summarized in Figure A-2.

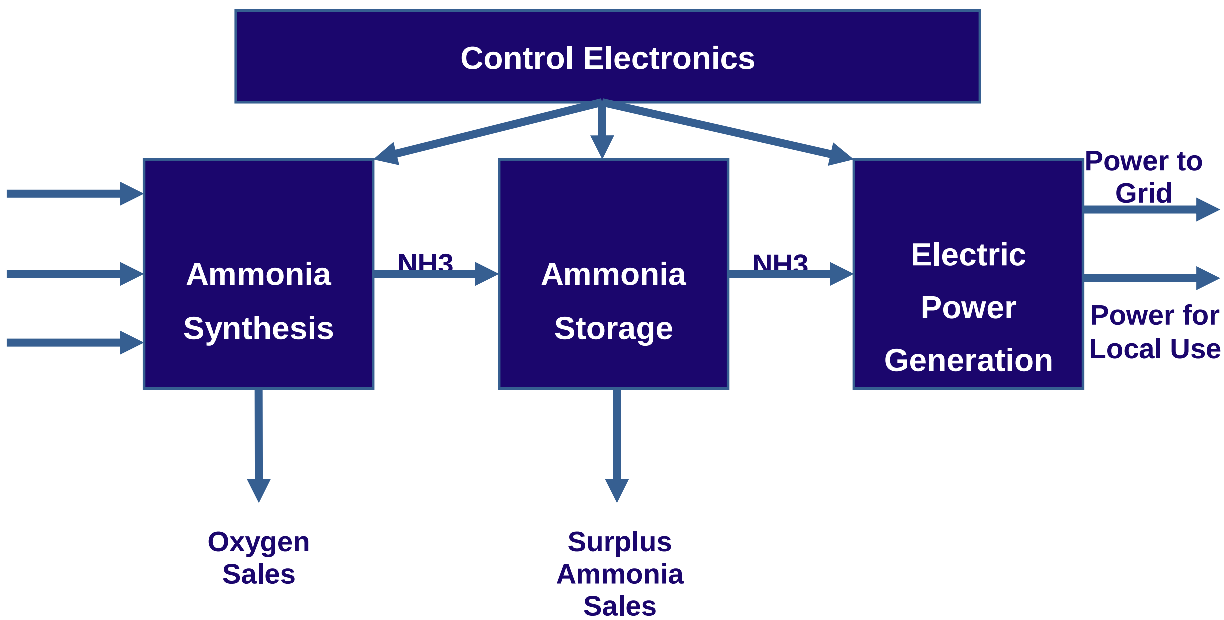

Figure A-2. Energy Storage Concept Using Anhydrous Ammonia.

Another storage option for the ammonia is to convert it to urea $(NH_2)_2CO$, which is a solid at room temperature rather than a liquid. This would allow thinner walled tanks for process equipment and other savings.

While not widely known, anhydrous ammonia has been used as a fuel in various applications for decades. Not normally considered a fuel, ammonia is widely used as fertilizer, and as a precursor of other chemicals including explosives and pharmaceuticals. Because anhydrous ammonia consists of hydrogen and nitrogen, it produces only water and nitrogen (neither of which is a GHG) when it is burned in a power plant to generate power. Some trace NOx may be produced, but is easily treated.

Converting diesel engines to run on ammonia seems to be a logical choice for the power plant in small-scale Hydrogen Hubs. This is because diesel GenSets are readily available from commercial suppliers such as Caterpillar, at reasonable cost. Diesel engines are also durable, reliable, and inexpensive to maintain. Because they are widely used in power applications, particularly emergency power supply, spare parts and services are readily available. The cost of converting a diesel engine to run on ammonia is a key uncertainty, as is the resulting operating efficiency.

Because a small amount of biodiesel fuel (or conventional diesel) is required to assist the ammonia combustion process in diesel (compression ignition) engines, a small amount of carbon dioxide is generated if diesel engines are used at the power plant because biodiesel fuel produces some carbon dioxide emissions. Other power plant technologies that would not potentially produce carbon dioxide include spark-ignited IC engines and combustion turbines. Significant uncertainties exist to convert these power plant technologies to run on ammonia, including costs and potential degradation in efficiency.

Because it is an energy storage device, a Hydrogen Hub will necessarily consume more power than it produces. Indeed, compared to other storage technologies, the "round trip" thermodynamic efficiency of a Hydrogen Hub, preliminarily estimated to be about 20 to 25 percent, is relatively low. Further, the capital costs of constructing a Hydrogen Hub as a peaking unit seem to be comparable to that of natural gas-fired combustion turbines.

While the operating costs of a Hydrogen Hub may be higher than using natural gas as a fuel, ammonia's relatively carbon-free and clean burning combustion characteristics, as well as its high energy content, seem to make ammonia a viable storage medium candidate. Ammonia is conveniently stored as a liquid at room temperature at pressures of approximately125 psi and greater, and is stored routinely in large quantities as a liquid at atmospheric pressure at -33°C. Further, ammonia production surplus to power plant needs could be marketed to agribusiness for use as fertilizer to help offset costs of providing power benefits. Similarly, oxygen, a byproduct of electrolysis of water, could be sold to help offset operating costs.

An ammonia powered GenSet could be called on to produce power when needed by the power system. Because the ammonia synthesis process can be turned on and off relatively quickly, a Hydrogen Hub could provide additional benefits to the power system by serving as a dispatchable load. These highly flexible operating characteristics suggest Hydrogen Hub technology could help integrate intermittent renewable resources, particularly wind power, into the power grid. Finally, while costs would increase somewhat, it may be possible to produce ammonia in one location, but construct ammonia powered GenSets in another location to provide transmission benefits. BPA has asked NWHA to conduct further study on these concepts.

In performing this preliminary study, NWHA looked at three cases. Case 1 estimated the costs of constructing and operating a small Hydrogen Hub with an ammonia plant with a 10 tons/day capacity coupled to a 10 MW GenSet. Case 2 estimated the costs of constructing and operating a Hydrogen Hub with an ammonia powered 25 MW GenSet just 2 months a year to sell into high priced summer power markets. Case 3 estimated the costs of constructing and operating a Hydrogen Hub with a 100 ton/day ammonia plant to produce ammonia surplus to the needs of an ammonia powered 10 MW GenSet.

In addition to the conclusions implicit in the discussion above, NWHA's preliminary major conclusions are that using a Hydrogen Hub as a peaking unit (Case 1) seems to be a potentially viable alternative, although operating costs would be high compared to other peaker technologies. Using a Hydrogen Hub as an energy resource (Case 2) does not seem to be a viable strategy, unless summer power prices are unusually high or other unlikely favorable conditions exist. Offsetting the costs of providing power benefits by selling ammonia surplus to power plant needs (Case 3), and possibly oxygen, seems to be a viable strategy. Oxygen is produced in a Hydrogen Hub at the rate of 1.4 tons of O2 per ton of NH3, and with purity sufficient to sell to end users. In summary, both Case 1 and Case 3 seem to merit further study.

BPA asked NWHA to perform additional work on Hydrogen Hubs. This work includes assessing the benefits of locating Hydrogen Hubs to provide power benefits, estimating issues associated with constructing utility-scale Hydrogen Hubs, and conducting an independent review of the science and technology contained in this preliminary report. To this end, NWHA retained several independent experts to review various aspects of the proposal and engage in discussions with BPA staff and others concerning locational benefits and issues of scale.

Independent reviewers included: Dr. Ibrahim Dincer, Professor of Mechanical Engineering, Faculty of Engineering and Applied Science, University of Ontario Institute of Technology (an expert on hydrogen); Dr. Michael Webber, Webber Energy Group, Engineering Professor at the University of Texas at Austin; Brian Jackson, Renaissance Engineering & Design (a engineer familiar with hydrogen production); Mark Rosenbury, an expert in ammonia; Norm Olson of the Iowa Energy Center, an expert on ammonia; Dr. Venki Raman, Protium Energy Technology (an expert on industrial gases); and JR "Buzz" Campbell and Maura Garvey, JR Campbell & Associates, Inc (experts on industrial gas markets).

A1.4 POTENTIALLY RELATED TECHNOLOGIES

A1.4.1 Battery Recycling Center

One potentially related technology is the recycling of battery components for batteries used in a clean energy concept. Rather than pay for recycling by an outside entity, a local recycling capability could be established.

A quick internet search provided numerous companies that advertise safe and cost-effective disposal of battery components, with costs that match the quantity and difficulty in providing those services. One such company is Battery Solutions that claims to provide this service on a nationwide scale. Many other companies offer like services.

A cost-benefit analysis would be required to evaluate the economic feasibility of a local battery recycling center, a cost-benefit analysis is recommended. Part of the analysis should include a determination of the kinds of battery components to be recycled. The Battery Solutions website includes information on recycling of various types of batteries, including lead acid, lithium, mercury, and zinc batteries.

One aspect of battery recycling that needs further investigation as part of the cost-benefit analysis is legal requirements, including the need for certification/recertification by responsible state and/or federal authorities. The cost and requirements for this certification are unknown, but potentially significant. For example, if periodic recertification is required, it would add to the cost of initial certification.

Other factors should also be considered during the cost-benefit analysis, including the availability of personnel with the requisite skills to safely perform this kind of tasking and familiarity with environmental considerations and regulations. Given the long history of nuclear-related technologies performed in the Tri-Cities area, it is expected that personnel would be readily available with the appropriate environmental and safety skills and required training. A final factor is the existence of excess electrical power during the spring when hydro power and wind power are both at their peak. While a year-round plant may not be economically feasible, a seasonal plant could be considered.

A1.4.2 Strawboard Production

Another potentially related technology is the production of strawboard. Excess wheat straw, which is to be used as feedstock for the clean energy generation project, could be made into strawboard. In addition to the availability of excess straw from the feedstock, the use of heat in the feedstock process will create a natural resin. These resins are suitable for use with the straw to create a strawboard product. The cost of adhesive resins limits the applicability of strawboard. However, the high value fermentation products previously discussed can be transformed into “green” resins.

Strawboard panels are rigid building panels and have a variety of uses in the building industry. According to the National Association of Home Builders, strawboard panels can be used to replace more labor intensive products, including two by four studs and drywall panels for interior partition walls. Use of these panels can reduce labor costs as they are more easily and rapidly installed. In addition, they have good sound and thermal insulation properties and are resistant to termites and fire. Finally, these panels are well suited to be worked with standard woodworking tools.

An analysis concerning the strawboard industry and strawboard production was conducted by WSU to assess the viability of constructing a strawboard-manufacturing plant (www.business.wsu.edu/SiteCollectionDocuments/CES/Strawboard.pdf).

In the Executive Summary, the following findings were documented:

> *Strawboard outperforms wood-based board due to possession of the following attributes: higher strength, superior dimensional stability, lighter weight, better machining characteristics, increased screw and nail holding ability, more moisture resistance, no formaldehyde emissions, improved laminating attributes, and fire resistance in some strawboard.*
>
> *In addition to superior workability, use of straw not only helps farmers deal with agricultural residues disposal problems, but also relieves wood shortage. Further, farmers can receive additional income by selling straw to strawboard manufacturing factories.*
>
> *The construction of a strawboard manufacturing plant requires capital investment of four million to fifty million dollars, varying by the scale of operation. The plant is usually located at the center of a straw procurement area. It is suggested that production of value-added final products would be more lucrative than a production of panels, which are more likely to be subject to dramatic price fluctuations.*

Moreover, a premium price for strawboard is recommended because of the use of a more expensive and non-toxic binder, better performance, and its environment-friendly advantages. Promotion of strawboard can be implemented via discounting large purchases and also by enclosing flyers in the package of products. The distribution channel for strawboard includes wholesalers and strawboard manufacturers themselves. Furthermore, establishing a purchasing alliance with home-improvement centers is also recommended.

The strawboard industry is burgeoning. Due to the similarity of strawboard to particleboard, in their applications as well as durability, strawboard is considered a proper substitute for particleboard; and its market potential is substantial.

Hence, the construction of a strawboard manufacturing plant in rural areas can considerably benefit rural economic development. This analysis indicates that it is feasible to establish strawboard manufacturing plants in rural areas.

A1.5 LOW-HEAD HYDRO

Low-head hydroelectric power, also called low-head hydro, includes mini and micro hydro, and is defined within the United States as shown in Table A-1 (www.microhydropower.net). Other nations have different definitions for the various categories. For example, the European Union defines micro hydro as less than 300 KW in size.

Table A-1. Low-Head Hydro Scaling.

Low-Head Hydro Technology	Micro	Mini	Small
United States	<100KW	100-1000KW	1-30MW

There are many installations of low-head hydro throughout the world, with the bulk of them being installed outside of the United States. This technology is attractive in that it is scalable to the demand, and it is economical because there is no requirement to purchase fuel. In some cases, it is considered beneficial to team low-head hydro power with PV installations because the availability of clean energy is seen as complementary. That is, in the winter season, where PV power generation is low, there tends to be an abundance of hydro power. On the other hand, hydro is not seen as effective to team hydro and wind power, as the abundance of wind energy is typically during the same season as hydro. That has certainly been the case in the Mid-Columbia region, as reported by the BPA.

Construction of low-head hydro projects is site specific and needs a supply of existing water. In the Mid-Columbia region, the Columbia River is an abundant resource of run-of-the-river hydro power that could be an excellent candidate to utilize this technology effectively. Typically, water moves through a pipe, sometimes called a penstock, due to the terminology used in large-scale hydroelectric power generation, see Figure A-3.

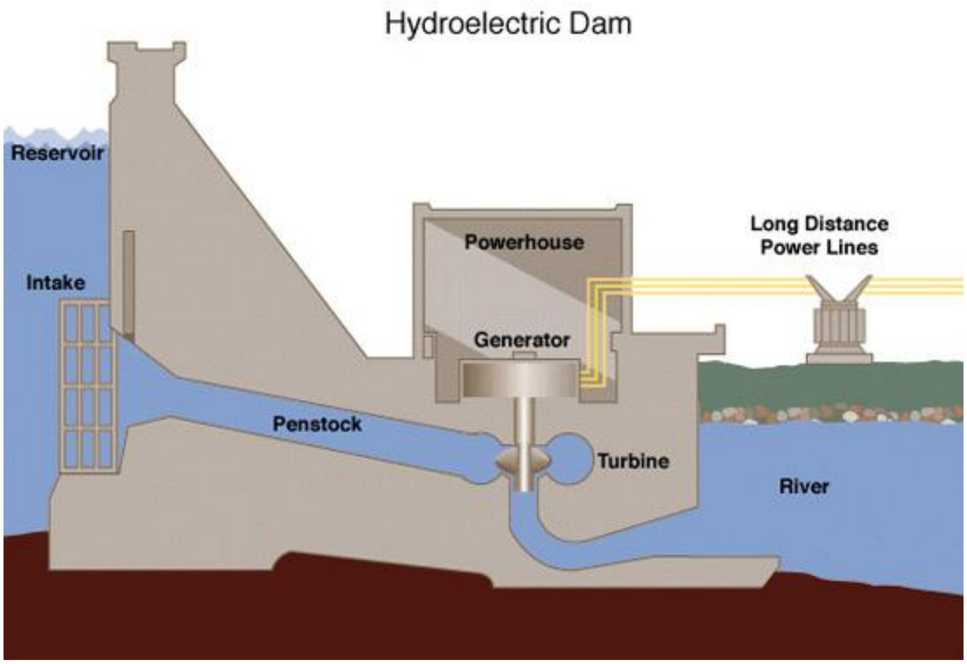

Figure A-3. Representative Hydroelectric Dam.

As in large-scale hydro, water is gathered through an intake and routed to a turbine-generator through the penstock and then returned to the river downstream. A similar, but much smaller approach has been demonstrated to be effective.

In low-head hydro (Figure A-4), however, the height of the water column (called head) is much smaller than for a large-scale hydroelectric dam. As a result, the turbine-generator used in a low-head hydro project must be matched to the available head and water flow available at the project site.

A1.6 GENERATION OF ANCILLARY BUSINESSES

This section of the appendix is a collection of ancillary businesses that could be supported as a result of creating a clean energy industrial base in the Mid-Columbia region. None of these businesses has been thoroughly investigated, nor is the list considered complete. It is simply a collection of the ideas generated by the study team that didn't fit elsewhere in the study report.

A1.6.1 New Railroad Car for Wheat Straw Transportation

One ancillary business idea is the design and manufacture of a new railroad car for the transportation of wheat straw to a biomass processing facility. During the investigation of the possible use of rail transport for the wheat straw feedstock, it was discovered that existing railcar designs are not well suited for this task. Covered hoppers and boxcars can probably perform the wheat straw transport but are believed to have significant drawbacks.

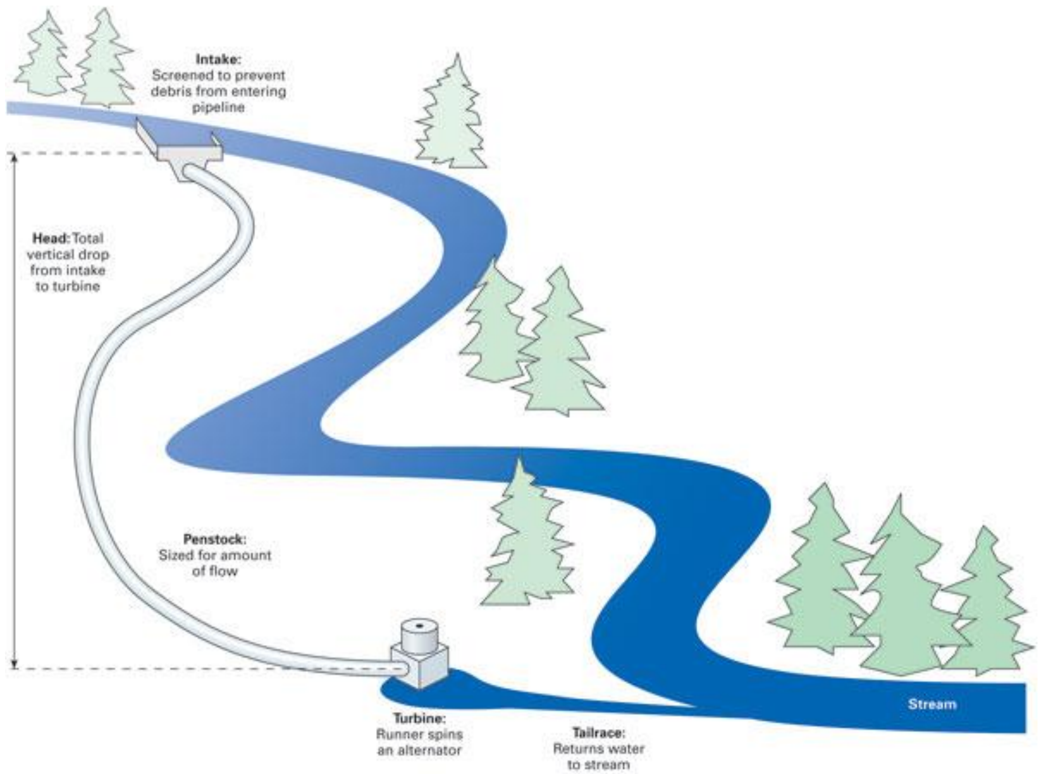

Figure A-4. Representative Low-Head Hydroelectric Project.

Boxcars are the most common type of railcar in use today to transport cargo and are designed to carry boxed, crated, or palletized freight (Guide to Railcars). While often used for bulky cargo, the nature of the wheat straw being delivered is not in keeping with the typical freight storage and handling practices used for boxcars. Hopper cars are designed to transport free flowing dry bulk commodities, including grains, as well as rock, gravel, and sand. Hopper cars are better suited to the transport of wheat straw than boxcars. Still, significant drawbacks are expected in their use.

Meetings were conducted with the Pacific Union Railroad and the local railroad, Tri-City & Olympia Railroad Company, to discuss the feasibility of using rail transport to deliver the large quantities of wheat straw feedstock to the prospective biomass facility. Because of the large quantities of feedstock to be delivered, it may be feasible to design a dedicated railcar for this task. Finally, once the railcar design is completed for this project, Tri-City & Olympia Railroad Company believes that other uses for the dedicated railcar may be identified. If true, this would sustain the production of wheat straw railcars well beyond those needed for efforts in the Mid-Columbia region.

A1.6.2 Railroad Shop

Similar to the new railcar design, the magnitude of the rail transportation required to deliver the wheat straw feedstock to the project will bring with it a large maintenance requirement for the train cars used. In addition to the maintenance and repair of the unique railcar design discussed above, other train cars might be readily maintained at that facility. This could include other hopper cars, boxcars, and perhaps even train engines.

A1.6.3 Crane Shop

Similar to the rail shop, the offload of the extremely large quantities of wheat straw feedstock will require the significant use of cranes. Several crane businesses reside in the area including Lampson Crane. In addition, the North Pacific Crane Company is located in Seattle, Washington. Hydra-Pro is also located in Seattle that provides crane manufacturing, equipment, and servicing.

APPENDIX B

SOLAR TRACKING MODELING RESULTS USING PHOTOVOLTIC SYSTEM FOR A 5 MW AC GROUND-MOUNTED SYSTEM (refer to Section 3.5.1.3)

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Grid-Connected System: Simulation parameters

Project : **Grid-Connected Project at Hanford PV**

Geographical Site	**Hanford PV**		**Country**	**USA**
Situation	Latitude	46.4°N	Longitude	119.2°W
Time defined as	Legal Time	Time zone UT-8	Altitude	153 m
	Albedo	0.20		

Meteo data : Hanford PV, NREL US TMY2

Simulation variant : **Hanford Poly 1 Axis Tracking**

Simulation date 06/10/11 19h14

Simulation parameters

Tracking plane, Horizontal E-W Axis			Normal azimut to axis	0°
Rotation Limitations	Minimum Tilt	10°	Maximum Tilt	80°
Backtracking strategy	Tracker Spacing	6.60 m	Collector width	3.00 m
Inactive band	Top	0.00 m	Bottom	0.00 m
Horizon	Free Horizon			
Near Shadings	No Shadings			

PV Array Characteristics

PV module Si-poly	Model	**STP 280-24/Vd**		
	Manufacturer	Suntech		
Number of PV modules	In series	17 modules	In parallel	1208 strings
Total number of PV modules	Nb. modules	20536	Unit Nom. Power	280 Wp
Array global power	Nominal (STC)	**5750 kWp**	At operating cond.	5156 kWp (50°C)
Array operating characteristics (50°C)	U mpp	552 V	I mpp	9340 A
Total area	Module area	**39847 m²**		
Inverter	Model	**Sunny Central 250 HE**		
	Manufacturer	SMA		
Characteristics	Operating Voltage	450-820 V	Unit Nom. Power	250 kW AC
Inverter pack	Number of Inverter	21 units	Total Power	5250 kW AC

PV Array loss factors

Thermal Loss factor	Uc (const)	20.0 W/m²K	Uv (wind)	0.0 W/m²K / m/s
=> Nominal Oper. Coll. Temp. (G=800 W/m², Tamb=20°C, Wind velocity = 1m/s.)			NOCT	56 °C
Wiring Ohmic Loss	Global array res.	1.0 mOhm	Loss Fraction	1.5 % at STC
Array Soiling Losses			Loss Fraction	1.0 %
Module Quality Loss			Loss Fraction	0.1 %
Module Mismatch Losses			Loss Fraction	2.0 % at MPP
Incidence effect, ASHRAE parametrization	IAM =	1 - bo (1/cos i - 1)	bo Parameter	0.05

User's needs : Unlimited load (grid)

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Grid-Connected System: Main results

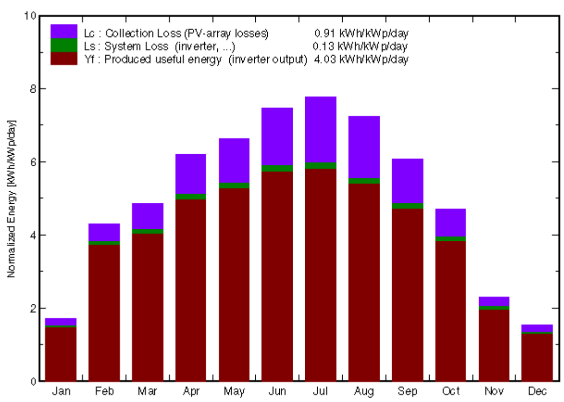
Project : **Grid-Connected Project at Hanford PV**

Simulation variant : **Hanford Poly 1 Axis Tracking**

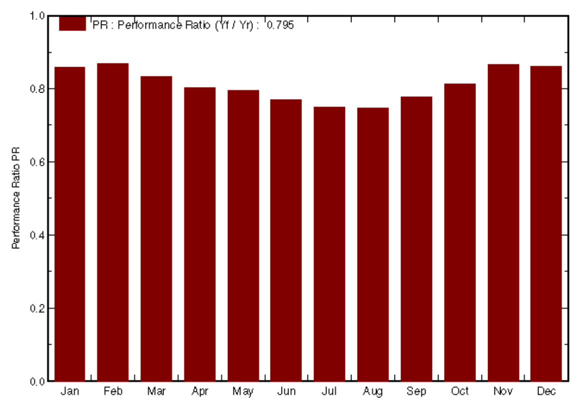
Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Tracking, horizontal axis E-W, Normal azimut to axis		Normal azimut to axis	0°
PV modules	Model	STP 280-24/Vd	Pnom	280 Wp
PV Array	Nb. of modules	20536	Pnom total	**5750 kWp**
Inverter	Model	Sunny Central 250 HE	Pnom	250 kW ac
Inverter pack	Nb. of units	21.0	Pnom total	**5250 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**8464 MWh/year**	Specific prod.	1472 kWh/kWp/year
	Performance Ratio PR	79.5 %		

Normalized productions (per installed kWp): Nominal power 5750 kWp



Performance Ratio PR



Hanford Poly 1 Axis Tracking
Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	35.8	0.78	53.5	51.5	275	264	12.91	12.37
February	70.1	0.68	120.3	117.3	621	601	12.95	12.55
March	113.3	8.89	150.4	146.1	745	722	12.42	12.04
April	163.5	14.22	186.3	180.8	886	860	11.94	11.58
May	196.1	16.56	205.8	199.9	971	942	11.84	11.48
June	219.3	21.55	224.3	217.9	1024	994	11.46	11.12
July	231.6	26.52	241.2	234.6	1070	1039	11.13	10.81
August	200.9	26.81	224.6	218.5	994	965	11.10	10.78
September	142.6	20.33	182.6	177.6	841	817	11.56	11.22
October	92.0	12.96	146.1	142.5	706	684	12.13	11.76
November	42.0	0.42	68.8	66.9	356	343	12.98	12.51
December	29.4	2.66	47.5	45.8	245	235	12.94	12.42
Year	1536.6	12.78	1851.4	1799.5	8734	8464	11.84	11.47

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

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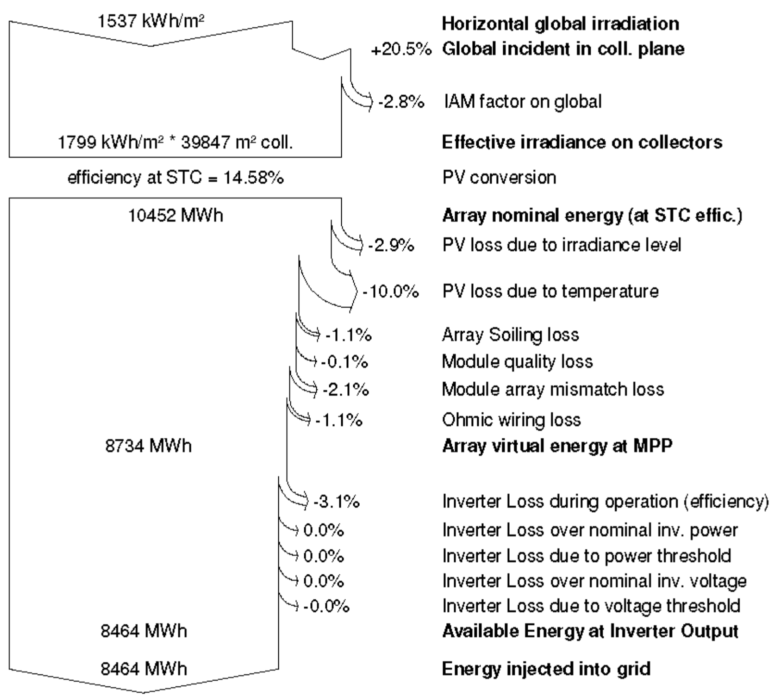
Grid-Connected System: Loss diagram

Project : **Grid-Connected Project at Hanford PV**

Simulation variant : **Hanford Poly 1 Axis Tracking**

Main system parameters	System type	**Grid-Connected**		
PV Field Orientation	Tracking, horizontal axis E-W, Normal azimut to axis		Normal azimut to axis	0°
PV modules	Model	STP 280-24/Vd	Pnom	280 Wp
PV Array	Nb. of modules	20536	Pnom total	**5750 kWp**
Inverter	Model	Sunny Central 250 HE	Pnom	250 kW ac
Inverter pack	Nb. of units	21.0	Pnom total	**5250 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



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