ALASKA ENERGY

A first step toward energy independence.

A Guide for Alaskan Communities to Utilize Local Energy Resources

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Alaska Energy Authority
Alaska Center for Energy and Power

ALASKA ENERGY AUTHORITY

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The narrative and model in this report are designed to provide information to engage Alaskans who have a passion to provide energy solutions, stimulate the Alaskan economy and provide leadership for the benefit of all Alaskans.

Alaska has had many high-quality energy plans written over the years, but none ever gained traction to come to fruition. To increase the likelihood that energy solutions will become a reality, the new approach will engage Alaskans in the solution and invite their active participation in the selection and ownership of their alternative energy sources.

The safe approach to conducting this work would have been to hire a consultant. With some risk but a large increase in the service to Alaskans, the Alaska Energy Authority chose to utilize the expertise of in-house staff. This personal accountability by the professionals at AEA will help ensure Alaskans have access to energy information and a single location they can work with to resolve their energy challenges and opportunities. As more information becomes available, the information will be placed in the energy model for use by decision makers long into the future.

Steven Haagenson
Statewide Energy Coordinator

Sustainable Energy for Alaskans

We Alaskans live in a magnificent state that has many blessings when it comes to energy, but also some curses. Alaskans live in a state with abundant energy resources, but are hampered by long distances and low usages.

The Alaska Energy Authority (AEA) has developed this document to act as a first step toward energy independence for Alaskans. The document contains two main sections - a narrative which you are reading now, and a technology screening tool we have developed to allow each community to review locally available resources and determine the least-cost energy options based on the delivered cost of energy to residents.

Energy use in each community is composed of three major components: electricity, space heating, and transportation. The relative level of use and cost for each of these components differs across Alaska. For instance, Anchorage residents pay comparatively less for electricity and space heating, but more for transportation due to heavy dependence on vehicle travel. Rural Alaskans see lower vehicle travel, but have much higher costs for heating oil and electricity.

All of America is struggling with the high cost of energy, but Alaskans have the resources, the ability, and the motivation to create long-term solutions that will greatly benefit our children and grandchildren. AEA's goal in developing the Alaska Energy Plan is to reduce the cost of energy to all Alaskans through deployment of energy technologies that are vertically integrated, economic, long-term stably priced, and sustainable.

In order to achieve this goal, we will be engaging Alaskans throughout the state who have the expertise and passion to use local resources to reduce their dependence on petroleum. This effort must be approached as a team effort, where each participant, private or public, can provide value for permitting, construction, applied research and development, natural resource management, financing, workforce development in management, design, business, construction, operations, economic development, wealth retention, and leadership.

Alaska Energy - First Steps

The first step in creating this document was to identify each community's current energy needs for electrical generation, space heating, and transportation. It is important to know these values as they provide a reference or measuring stick against which we can measure alternatives. Electric power usage was obtained directly from current PCE reports, while heating oil and transportation was estimated by the Institute of Social and Economic Research (ISER) based on modeling.

AEA conducted 28 Town Hall Meetings across the state, engaging many Alaskans through the process of seeking answers to three fundamental questions: 1) What resources near your community - where you live, work, play, fish, and hunt - could possibly be developed to help lower energy costs? 2) What resources should not be developed? 3) Why not?

The information gathered from these Town Hall Meetings was used to develop a resources matrix for each community. Potential resources identified included hydroelectric, in-river hydro, wind, solar, wave, tidal, biomass, geothermal, municipal waste, natural gas, propane, coal, diesel, coal bed methane, and nuclear. Also identified were opportunities for gasification and production of Fischer-Tropsch liquids.

For each resource, AEA formed Technology Teams made up of people with expertise and a passion for energy solutions who were asked to identify technologies options and limitations for each identified resource. The Alaska Center for Energy and Power (ACEP) at the University of Alaska was brought in initially to help guide the technology discussions, and ultimately went above and beyond in their work on the narrative and the comparative database.

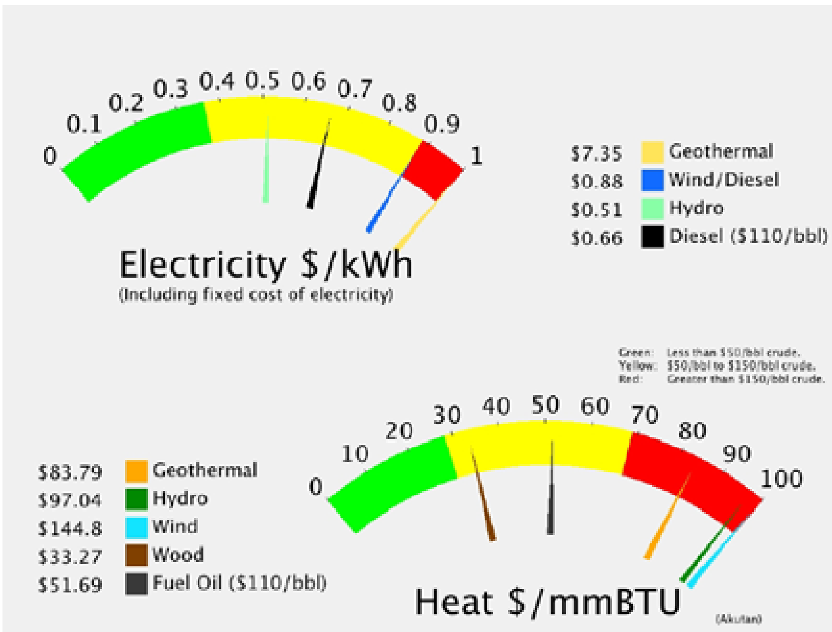
Appropriate technologies for each fuel have been identified. Capital and operations and maintenance costs for each technology have been determined and adjusted by region through use of factors developed by HMS Construction Cost Consultants.

The net result is a focusing tool that will provide each community with a high-level snapshot of the least-cost options for electricity, space heating, and transportation for their community. Prices will be based on a delivered cost that includes capital cost for infrastructure. The delivered cost number can be used to quickly compare the alternative energy options to diesel fuel based on a range ($50-$150) of crude oil prices.

This first step in the ongoing Energy Plan is intended to provide a high-level tool to focus each community on its relative options for generating electricity and heat through the use of locally available resources. This is an important step in developing a community, regional, and statewide energy plan. This process is intended to occur in stages, and it allows the state to provide assistance with maximum support and buy-in from Alaskans. Starting at the local level and using this plan as a building block to develop regional and statewide energy plans, the goal is to engage citizens directly in developing energy solutions for Alaska.

How this Document Should be Used

The illustration on this page shows a sample community energy meter. The energy meter is part of the technology screening tool and allows for a quick comparison between alternative energy options based on a range of future crude oil prices for each community in the state. As part of this screening analysis, current electric and space heating costs are compared on a total cost basis with capital, operation and maintenance (O&M), and fuel costs for various technologies. The focus is on near-term, commercial, and proven technologies, although an assessment of some pre-commercial or potential future options are also included.



The options for each community are compared with the current cost of energy as well as a diesel equivalent range of $50/bbl crude oil (low projection) to $150/bbl (high projection). There are many communities with access to alternative resources that can potentially provide energy at a cost below the diesel equivalent of $50/bbl crude oil. A sub $50 resource is defined as the Green Zone and can include wood (biomass) heat and wind/diesel options in the short term, as well as hydroelectric or geothermal options in the long term. The projection indicates that a Green Zone option alternative could reduce energy costs even when crude oil is at $150/bbl.

For most communities, the resource options fall within the cost range for diesel equivalent with crude oil between $50/bbl and $150/bbl. The $50-$150 range is considered the Yellow Zone and can include the entire range of energy alternatives.

Some communities have options that exceed the diesel equivalent of $150/bbl. This range is considered the Red Zone and indicates resources that are probably not cost-effective to develop at this time. If no other resources exist, a broader regional evaluation should be conducted to search for available options in nearby communities with Green or Yellow Zone resources. The high cost is likely a function of the size of the community, or the distance to available resources.

In some communities, the resource capability is much larger than the current energy requirements of the community. For resources developed to their full capacity but only using a portion of the energy, the cost would be high and could shift into the Red Zone. This is the case with some of the larger hydroelectric and geothermal resources. In this case, the community could look at ways to use excess capacity from the resource to spur economic growth opportunities and lower the cost of energy to residents.

There are several communities that do not have any viable alternative energy resources. This finding demonstrates the need to follow up with regional evaluations to assess potential alternatives beyond the immediate area of the community. It is also

How this Document Should be Used

likely that some communities are too small or too remote, and the most economic answer would be to continue to use diesel fuel for the forseeable future. However, this analysis indicates that most communities have at least one opportunity to reduce diesel use, even if solely through implementing efficiency measures.

We believe that use of local resources will help stabilize local economies by developing jobs to build, operate, and maintain energy systems. Local jobs will also be created where fuel collection, processing, and transportation are required. In this way, the dollars currently spent on diesel fuel could be recirculated within a community and used to strengthen the economic base.

The next step is to engage Alaskans at the regional level to discuss results from this screening tool. These regional meetings will provide a forum for additional community input. Meetings will also be conducted with utilities, municipalities, and native corporations to develop public/private partnerships and engage these entities in developing long-term energy solutions. Local buy-in will permit more focused regional feedback to the legislature, thus insuring that the best options are being recommended for approval. The screening tool is also designed to be continually updated as more information is available. In this way it will serve as a valuable tool for the legislature and governor when they consider energy requests in future capital budgets.

The focus of this work is on the non-Railbelt portions of Alaska. That is where the need to reduce energy costs is greatest. The Railbelt will be addressed through an Integrated Resource Plan (IRP), which will evaluate multiple energy sources and delivery systems. It is likely that the solution for the Railbelt will be a combination of available resources such as large hydroelectric projects, natural gas supplies, pipelines, biomass, wind, and geothermal systems.

How this Document Should be Used

Alaska has abundant resources and Alaskans have enjoyed relatively low-cost diesel prior to the pricing surge in 2007 that extended through the summer of 2008. When fuel prices are low and stable, interest in the use of locally available alternative fuels is low. When prices spike, interest likewise becomes high, but the opportunity to use lower-cost fuels may not exist without proper planning, research, and development. During oil price spikes in the 1980s, there was much interest in alternative energy across the nation, including Alaska. Nevertheless, projects such as the Susitna Hydroelectric Dam were canceled when crude oil dropped to $9.00 per barrel.

We have recently seen the price of crude drop from $124/bbl to $28/bbl, and lower, in a reduction similar to the one in the 1980s. This drop in oil prices hits Alaska doubly hard, as a reduction in state revenue limits funds available to develop the necessary infrastructure needed to switch to lower-cost fuels when crude oil prices again rise. The general consensus is that oil prices will again rise, but there is on-going debate about the future price of crude oil and the long-term volatility. Alaska is an oil-producing and exporting state, but there are many external factors that will increase or decrease crude oil pricing. In a global market with large consumers like India and China, Alaskans will be riding the market roller coaster with little influence on the final price determination. What can be controlled in this energy world?

Alaska has numerous energy resources and the power to choose its fuel supplies. A method is needed to place these choices in perspective. Public awareness needs to increase. There may be energy options that can provide lower-cost energy than today's $50/bbl oil. Resources that could be used to power and heat Alaskan communities and provide opportunities for local economic development should not sit unused. Alaskans must make the commitment to shift from diesel as much as possible, even when prices are low, if we are to avoid high costs in the future.

This document can provide insight into the energy opportunities that lie ahead for Alaskans. The technology screening database is based on data collected from numerous sources throughout the state. Where data has not been collected, models were developed to approximate the missing data. For example, ISER developed a model to predict the amount of heating oil used for spacing heating and vehicular transportation by community.

Data pertaining to population change and Power Cost Equalization has also been incorporated and is felt to be reliable and accurate.

The cost estimates contained in this report were conducted at the conceptual level with no site-specific design or scope development. Cost estimates were based on similar historical energy projects constructed in Alaska, vendor estimates, and historical studies and reports for specific applications. These need to be recognized for what they are: high level conceptual cost estimates. The recommendations are based on the best data currently available, but detailed site specific cost estimates must be completed prior to project selection to determine more accurate values.

How this Document Should be Used

The technology screening tool exists in two sections. The first is the energy meter page for a fast scan of local resources. The second is in a numeric results format for a more in-depth analysis of the data.

The energy meter page has been prepared for every community in Alaska located “outside” the Railbelt region. The numbers are reported as specific values for convenience, but in actuality contain a high degree of uncertainty as a result of incomplete data, conceptual cost estimates and estimates based on models. They are intended to provide an approximate value for the delivered cost of energy from a particular resource. Prior to finalization of an energy resource selection, a detailed site-specific cost estimate must be done to determine actual project costs for financing and benefits evaluation.

The energy meter page has two meter faces, one for the cost of electricity and one for the cost of space heating. The meter dial has three colors, green, yellow, and red. They are linked to the cost of crude oil. In the past few months, crude oil prices have ranged between \$150/bbl to \$30/bbl. With the price volatility of crude oil, the meter face was developed to show the locally available energy sources with respect to a variable pricing of crude oil. Rather than predict the future price of oil, the green, yellow, and red zones have been created. The Green Zone defines relative costs for crude oil pricing of \$50/bbl or less. The Yellow Zone defines cost above \$50/bbl, but below \$150/bbl. The Red Zone represents crude oil costs above \$150/bbl.

The cost of electricity and space heating from diesel fuel shown on the meters are computed using the price of crude oil, delivered to the community and used in the existing infrastructure. The electrical costs include non-fuel costs so the electrical cost shown will relate to the cost per kilowatt-hour shown on the billing statement, prior to the applicable PCE reduction.

A community can select its fast scan sheet and look for resources in the Green Zone. If resources exist in the Green Zone, this is an indication that local resources might provide a less expensive stable-priced energy source, even if the cost of crude oil were to rise. Green Zone resources should be reviewed for projected construction costs and time, since the most economic projects, such as hydro or geothermal, tend to have a longer construction time. If all Green Zone projects have long construction times, look at the Yellow Zone for resource options with a shorter delivery schedule.

The Yellow Zone is the range of possible crude pricing we have seen over the past few months. Predicting crude oil prices can be risky if not impossible. The recent reduction in crude prices is believed to be temporary, but exactly when and how much prices will rise is not known. If resources exist in the Yellow Zone, this indicates that the alternative resource may not be economic unless crude oil prices were to rise. This is also the zone where the state could assist in paying down the capital debt component to reduce the resultant cost of energy to the community. If \$50/bbl is the target point for state assistance, then, rather than paying the entire capital cost of the alternative project, the state assistance should be limited to paying capital costs down to the Green Zone or the \$50/bbl target point. Using the target point concept will help produce alternative energy at a level that can be sustained. For example, large hydroelectric projects are capital intensive but have low O&M cost on the order of \$0.01/kWh. Rather than assuming full capital relief and yielding the low O&M cost only, a balance of loans and grants could be applied to bring the resulting energy costs down to the pricing point equivalent. The all or nothing approach to capital funding may result in the wrong pricing signal for energy, and over-expend funds in one area while other areas will be paying much higher prices. Both short and long-term projects can exist in the Yellow

Zone. As the values of resources have a wide range, several of the lower-cost options should be reviewed for further investigation. As a general rule, short term projects should be selected first, with the addition of larger or longer term projects that will further reduce the cost of energy to the community.

The Red Zone includes projects that are not cost effective at this time and will not be so unless technology develops to reduce the resulting energy cost, or until crude oil is above the $150/bbl price.

The numeric results sheet can be used for a more in-depth analysis of the data. The first part identifies the current energy needs and costs for electricity, space heating, and transportation.

The current use can be compared to the existing capacity and energy usages to determine the general resource size required for the community. If a selected resource is much larger than the community needs, an economic development opportunity exists. For the community to achieve the lowest price, the resource will need to be used to its maximum. In this case, additional loads must be developed to match the capacity of the energy resource. For example, if a geothermal source exists that is larger than the community needs, the community could develop a fish cannery and use an absorption chiller to make ice in the summer or grow vegetables under grow-lights in a geothermally heated greenhouse in the winter.

Financing of energy projects is expected to be a mix of bonds, loans, private equity, grants or financial guarantees. To ensure the financial success of energy projects, good business practices would require the creation of a project scope, cost estimate, project business plan, management team, design team, financing plan, and permitting strategy. Business plan development will also be necessary for grant and loan approval, with an evaluation of the balancing of the risks and rewards. The community energy model can be used to analyze and compare different methods and levels of financing and grants.

Learning from history, we need to recognize past performance, to avoid the historical results of alternative energy plans described in the 'History of Energy Policy in Alaska' section of this document.

Specific factors which impeded success of alternative energy initiatives as stated in the House Research Report 85-C published in 1985 include:

- State agencies did not develop strong management capabilities
- State agencies lacked methods for assessing the technical and financial feasibility of projects
- Coordination among state agencies was often lacking
- Features of an alternative technology were poorly matched with a useful rural application
- Unrealistic expectations existed about what an agency or technology could accomplish
- Too much responsibility was delegated to contractors while the state often assumed the risk in performance of the project

Development of public/private partnerships is critical for successful implementation, with recognition of our respective strengths and weaknesses to ensure all parties are providing quality service to the effort.

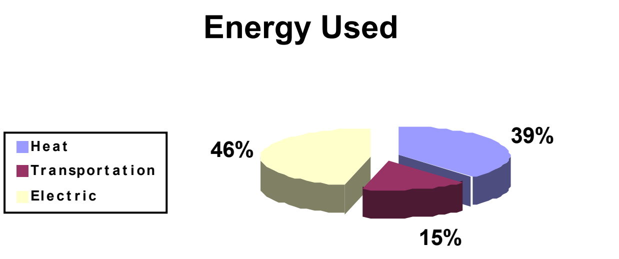
Private sector development by electric utilities, native corporations, municipalities and other qualified entities will provide access to management, business and operations expertise. Detailed business planning at the local level will ensure the technical and financial feasibility of the projects. The business plans will be required in all applications for state assistance and be a core part of the evaluations by state agencies, similar to the Renewable Energy Fund - Request for Applications evaluation and selection process. The local business plans will provide a tool to help identify and evaluate the best application of an alternative resource. The risks and rewards must be balanced and shared by the private, public and construction sectors.

Engaging Alaskans

The AEA team will engage Alaskans through a series of public meetings across the state. Regional meetings will be conducted in early 2009. The public meetings will be used as an opportunity to explain to local residents the use and the results of the report. This is also an opportunity to obtain feedback from Alaskans on the initial results and to obtain additional input. These discussions are an important step in creating a regional vision for energy development that has local support and buy-in. The AEA team will discuss specific local opportunities and explain the use of the report in a large group setting.

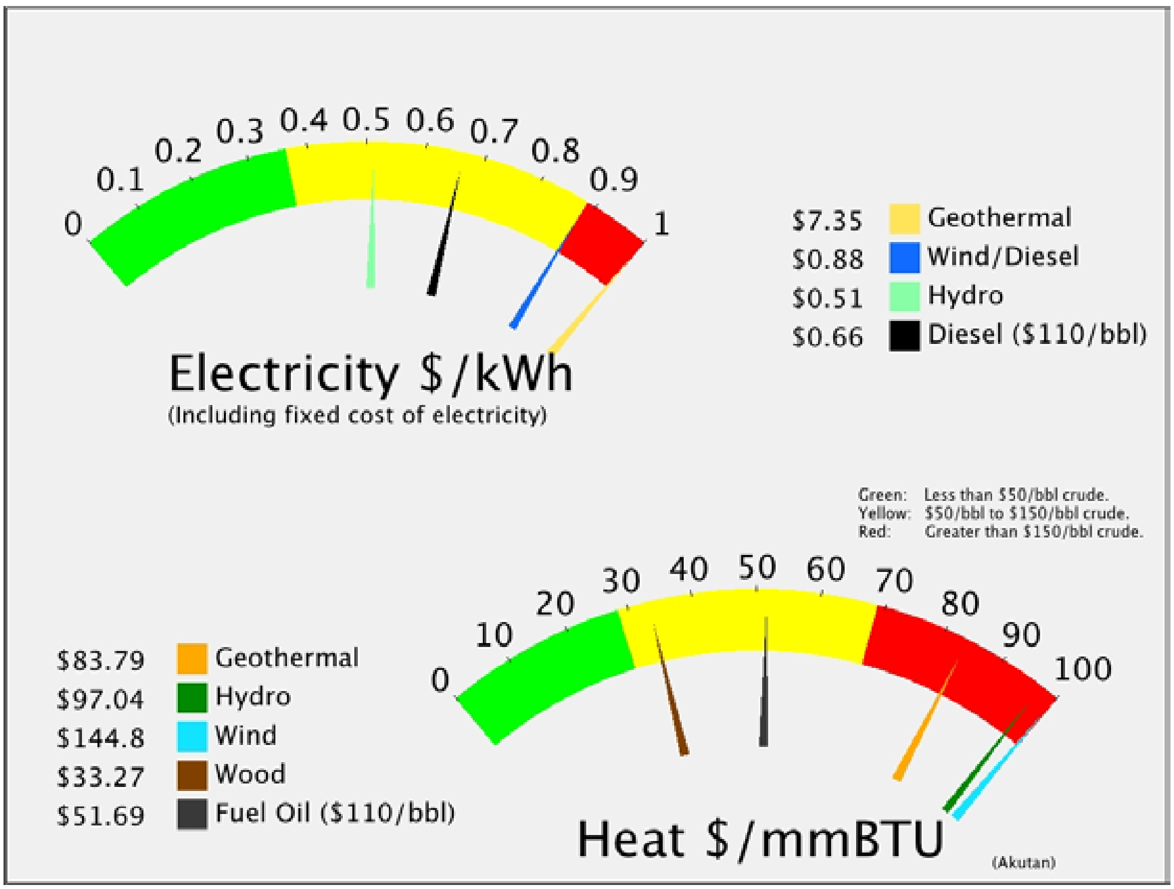
In addition to the public meetings, the AEA team will meet with the local municipalities, utilities, native corporations, and other groups with an interest in resolving the Alaskan energy challenge. These discussions will be conducted in smaller group settings and will help identify the people who have passion, expertise, knowledge and a realistic perspective for a specific resource and technology.

Akutan



Total:	**$964**	Per capita
Heat	**$372**	Per capita
Transportation	**$147**	Per capita
Electricity:	**$444**	Per capita

POPULATION: 859



Akutan

Regional Corporation
Aleut Corporation

House 37
Senate : **S**

POPULATION 859 LATITUDE: 54d 08m N LONGITUDE: 165d 46m **Aleutians East Borough**

LOCATION Akutan is located on Akutan Island in the eastern Aleutians, one of the Krenitzin Islands of the Fox Island group. It is 35 miles east of Unalaska, and 766 air miles southwest of Anchorage.

ECONOMY Commercial fish processing dominates Akutan's cash-based economy, and many locals are seasonally employed. Trident Seafoods operates a large processing plant west of the City for cod, crab, pollock and fish meal. The population of Akutan can double during processing months. Seven residents hold commercial fishing permits, primarily for halibut and other groundfish. Subsistence foods include seal, salmon, herring, halibut, clams, wild cattle, and game birds.

HISTORY Akutan began in 1878 as a fur storage and trading port for the Western Fur & Trading Company. The company's agent established a commercial cod fishing and processing business that quickly attracted nearby Unangan to the community. A Russian Orthodox church and a school were built in 1878. Alexander Nevsky Chapel was built in 1918 to replace the original structure. The Pacific Whaling Company built a whale processing station across the bay from Akutan in 1912. It was the only whaling station in the Aleutians, and operated until 1939. After the Japanese attacked Unalaska in June 1942, the U.S. government evacuated Akutan residents to the Ketchikan area. The village was re-established in 1944, although many villagers chose not to return. This exposure to the outside world brought many changes to the traditional lifestyle and attitudes of the community. The City was incorporated in 1979.

Current Energy Status PCE

Electric (Estimates based on PCE)

Current efficiency	**11.81**	kW-hr/gal	Fuel COE	**$0.45**	/kw-hr
Consumption in 2007	**48,913**	gal	Est OM	**$0.02**	/kw-hr
Average Load	**58**	kW	NF COE:	**$0.19**	/kw-hr
Estimated peak load	**116.51**	kW	Total	**$0.66**	
Average Sales	**510,306**	kW-hours			

Estimated Local Fuel cost @ $110/bbl	**$4.71** /kw-hr
Estimated Diesel OM	**$10,206**
Other Non-Fuel Costs:	**$98,502**
Current Fuel Costs	**$230,488**
Total Electric	**$339,196**

Space Heating (Estimated)

2000 Census Data	
Fuel Oil:	**100%**
Wood:	**0%**
Electricity:	**0.0%**

2008 Estimated Heating Fuel used:	**56,012**	gal
Estimated heating fuel cost/gallon	**$5.71**	
$/MMBtu delivered to user	**$51.81**	
Community heat needs in MMBtu	**6,721**	

Total Heating Oil **$319,950**

Transportation (Estimated)

Estimated Diesel: **22,154** gal Estimated cost **$5.71**

Total Transportation **$126,547**

Energy Total **$785,693**

Possible Upgrades to Current Power Plant

Power Plant - Performance Improvement to higher efficiency

Upgrade needed:

Semiannual Circuit Rider

Status **Completed**

Acheivable efficiency **14** kW-h

New Fuel use **41,267**

Capital cost	**$7,500**		
Annual Capital cost	**$628**	$0.00	/kw-hr
Estimated Diesel OM	**$10,206**	$0.02	
New fuel cost	**$194,457**	$0.38	
Avg Non-Fuel Costs:	**$108,708**	$0.19	
New cost of electricity		**$0.55** per kW-hr	

Savings

$35,402

Diesel Engine Heat Recovery

Heat Recovery System Installed?

Is it working now?

BLDGs connected and working:

				Value
Water Jacket	**7,337**	gal		**$41,910**
Stack Heat	**0**	gal		**$0**

Capital cost	**$163,112**
Annual ID	**$13,663**
Annual OM	**$3,262**
Total Annual costs	**$16,926**
Heat cost	**$20.88** $/MMBtu

Savings

$24,985

Alternative Energy Resources

Geothermal

Installed KW **5000**

kW-hr/year **41610000**

Site Name **Akutan - Shallow**

Project Capactity **200 MW**

Shallow Resource **0** Feet

Shallow Temp **99.00** C

		per kW-hr	Heat Cost $/MMBtu :
Capital cost	**$38,500,000**		
Annual Capital	**$2,587,805**	$0.06	$18.22
Annual OM	**$1,155,000**	$0.03	$8.13
Fuel cost:	**$0**	$0.00	
Total Annual Cost	**$3,742,805**	$0.09	**$26.36**
Non-Fuel Costs		$0.21	
Alternative COE:		**$0.30**	
% Community energy		8154%	
New Community COE (includes non-fuel and diesel costs)		**$7.55**	

Savings

($3,403,609)

Geothermal

Installed KW **6000**

kW-hr/year **49932000**

Site Name **Akutan - Deep**

Project Capactity **200 MW**

Shallow Resource **0** Feet

Shallow Temp **99.00** C

		per kW-hr	Heat Cost $/MMBtu :
Capital cost	**$37,500,000**		
Annual Capital	**$2,520,589**	$0.05	$14.79
Annual OM	**$1,125,000**	$0.02	$6.60
Fuel cost:	**$0**	$0.00	
Total Annual Cost	**$3,645,589**	$0.07	**$21.39**
Non-Fuel Costs		$0.21	
Alternative COE:		**$0.29**	
% Community energy		9785%	
New Community COE (includes non-fuel and diesel costs)		**$7.36**	

Savings

($3,306,393)

Hydro

Installed KW	**197**	Capital cost	**$2,507,920**	per kW-hr	Heat Cost $/MMBtu :
kW-hr/year	**566166**	Annual Capital	**$97,472**	$0.17	$50.44
		Annual OM	**$55,200**	$0.10	$28.57
Site	**North Creek**	Fuel cost:	**$0**	$0.00	
Study plan effort	**feasibilty**	Total Annual Cost	**$152,672**	$0.27	**$79.01**
Plant Factor	**69** %	Non-Fuel Costs		$0.21	
Penetration	**0.52**	**Alternative COE:**		**$0.48**	
		% Community energy		111%	**Savings**
		New Community COE (includes non-fuel and diesel costs)		**$0.51**	**$186,524**

Hydro

Installed KW	**209**	Capital cost	**$2,509,760**	per kW-hr	Heat Cost $/MMBtu :
kW-hr/year	**701186**	Annual Capital	**$97,543**	$0.14	$40.76
		Annual OM	**$55,200**	$0.08	$23.07
Site	**Loud Creek**	Fuel cost:	**$0**	$0.00	
Study plan effort	**feasibility**	Total Annual Cost	**$152,743**	$0.22	**$63.83**
Plant Factor	**77** %	Non-Fuel Costs		$0.21	
Penetration	**0.54**	**Alternative COE:**		**$0.43**	
		% Community energy		137%	**Savings**
		New Community COE (includes non-fuel and diesel costs)		**$0.51**	**$186,453**

Wind Diesel Hybrid

Installed KW	**600**	Capital cost	**$4,253,640**	per kW-hr	Heat Cost $/MMBtu :
kW-hr/year	**1218860**	Annual Capital	**$285,911**	$0.23	$68.73
		Annual OM	**$57,184**	$0.05	$13.75
Met Tower?	**no**	Fuel cost:	**$0**	$0.00	
Homer Data?	**yes**	Total Annual Cost	**$343,096**	$0.28	**$82.48**
Wind Class	**7**	Non-Fuel Costs		$0.21	
Avg wind speed	**8.50** m/s	**Alternative COE:**		**$0.49**	
		% Community energy		239%	**Savings**
		New Community COE (includes non-fuel and diesel costs)		**$0.89**	**($3,900)**

Railbelt Region

Opportunities and challenges in the Railbelt Region differ from those in other parts of Alaska. The Railbelt electrical grid is defined as the service areas of six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association (GVEA); Chugach Electric Association (CEA); Matanuska Electric Association (MEA); Homer Electric Association (HEA); Anchorage Municipal Light & Power (ML&P); the City of Seward Electric System (SES); and Aurora Energy, LLC as an independent power producing utility. Sixty five percent of Alaskan population lies within the Railbelt region.

The southern portion of the Railbelt: Mat-Su Valley, Anchorage, and the Kenai Peninsula are highly dependent on natural gas as a source of electricity and heat. The northern portion of the Railbelt including Fairbanks and other communities in the Interior relies on petroleum fuels in addition to natural gas, coal and hydroelectric electrical imports from the south. Petroleum fuels provide the majority of energy used for transportation across the entire state.

Nearly all of the thermal generating capacity in the Railbelt is more than 20 years old, and much of it is more than 30 years old. The majority of the generation is predominately combustion turbine generation. There are five utilities to the south of the Alaska Range. GVEA is the sole utility to the north.

A Regional Integrated Resource Plan (RIRP) is being developed to identify and evaluate the best resource mix to insure that least-cost options for electricity and heat are developed in the Railbelt region. The RIRP will be completed in late 2009 and will consider multiple energy options and make a recommendation on specific projects to be developed.

The complete Request for Proposals on the Regional Integrated Resource Plan for the Railbelt Region of Alaska can be found on the Alaska Energy Authority website, www.akenergyauthority.org.

The current generation mix includes a number of existing hydroelectric power plants that are operating in the southern portion of the Railbelt. Two coal-fired power stations (one operational) are positioned within GVEA's service area at Healy River, near extensive sub-bituminous coal resources available from the Usibelli coal mine.

The Cook Inlet gas basin still yields large quantities of natural gas for power generation and space heating, but known reserves are now falling and dropping field operating pressures are causing concern that the region may not be able to depend on lower Cook Inlet for adequate gas supplies in the future. There are several proposals to construct pipelines that could bring Alaskan North Slope natural gas into the Railbelt. Consideration of these potential fuel sources will be a part of the integrated resource plan for the Railbelt.

A number of future generation projects have also been proposed, among them wind power projects, large-scale and small-scale hydroelectric power projects, Fischer-Tropsch plants, coal-fired power stations, and turbines fired by fuel oil or natural gas turbines.

Future fuel supplies for the Railbelt are diverse. Near-term fuel supplies include natural gas from the Lower Cook Inlet Basin, petroleum fuel supplies from Fairbanks and Kenai Peninsula refineries, and coal resources near Healy and Chuitna. Significant quantities of North Slope natural gas are also available, although there is no pipeline currently available to bring this gas to the Alaska Railbelt. Trucking of LNG from the North Slope is being investigated as an interim opportunity to use North Slope natural gas to reduce the cost of energy to the

Fairbanks area. If the large-scale Alaska Natural Gas Pipeline is constructed, then significant quantities of natural gas will become available in Fairbanks. A compendium of known reports, RCA orders, and other data are available on the AEA website at www.akenergyauthority.org/USOhomepage.html, via the 'Resource Documents' link under the section, **Existing Railbelt Electric Grid data.

The Susitna Hydro Evaluation Project

The large-scale Susitna Hydro Project was proposed in the 1980s to provide hydroelectric power for the Railbelt. It was evaluated extensively by the state, but tabled in 1985 when oil prices dropped precipitously. AEA is currently engaged in the re-evaluation of the feasibility of this project. Historical information about the Susitna Hydro Project is available at http://www.akenergyauthority.org/SusitnaReports.html.

AEA intends to complete these studies on or before June 1, 2009. The RIRP for the Railbelt will require consideration of information from the Susitna Hydro Evaluation Project.

The Railbelt Electrical Grid Authority Project

AEA recently completed the Railbelt Electrical Grid Authority (REGA) Project, which recommends business structures that will own, operate, maintain, and control generation and transmission assets throughout the Railbelt.[1] The project considered several different energy futures for the Alaska Railbelt, and a regional plan for generation and transmission was part of this study. The final report and other resource documents are available online at http://www.akenergyauthority.org/REGAHomePage.html.

Regional Integrated Resource Plan (RIRP) for the Railbelt

The goal of the Regional Integrated Resource Plan for the Railbelt (RIRP) is to minimize future power supply costs and maintain or improve current levels of power supply reliability through the development of a single, comprehensive resource integration plan. The plan will identify and schedule a combination of generation and transmission (G&T) capital projects over a 50-year time horizon.

Healy Clean Coal Project

Railbelt Region

The plan is intended to provide:

- An assessment of loads and demands for the Railbelt Electrical Grid for a time horizon of 50 years, including new potential industrial demands;
- Projections for Railbelt electrical capacity and energy growth, fuel prices, and resource options;
- An analysis of the range of potential generation resources available, including costs, time for construction, and long-term operating costs;
- A schedule for existing generation project retirement, new generation construction, and construction of backbone-redundant transmission lines that will allow the future Railbelt Electrical Grid to operate reliably under open access tariffs, with a postage stamp rate for electricity and demand for the entire Railbelt as a whole;
- A long-term schedule for developing new fuel supplies that will provide for reliable, stably-priced electrical energy for a 50-year planning horizon;
- A diverse portfolio of power supply that includes in appropriate portions renewable and alternative energy projects and fossil fuel projects, some of which could be provided by independent power producers;
- A comprehensive list of current and future generation, transmission, and electric power infrastructure projects, each one including a project description, narrative, location, fuel source, estimated annual fuel consumption, power output capacity, and energy output, both annually and monthly.

For reasonable generation fuel supply configurations, the RIRP will develop and recommend up to three feasible resource plan scenarios, complete with assessment of costs and benefits, and collective and individual impacts on utility tariffs.

The RIRP will include consideration of the following energy sources:

- Healy Clean Coal Project
- Susitna Hydroelectric Project (including phased development)
- Chakachamna Hydroelectric Project
- Fire Island Wind Power Project
- Eva Creek Wind Project
- Fairbanks Fischer-Tropsch Project (energy source and fuel source)
- Chuitna Coal Project (energy source and fuel source)
- Nenana Basin natural gas
- New gas reserves and exploration in Cook Inlet
- North Slope natural gas Bullet Line
- LNG trucked from the North Slope to Fairbanks

In order to integrate Susitna development with Railbelt Electrical Grid capacity and energy needs the RIRP will consider a number of options for bringing generation sources online, including the phased development of the Susitna Hydro Electric Project. The RIRP will also consider input from the Wind Integration Study currently being conducted by AEA, and it will include an analysis of the role of demand side management rules and the ability to reduce generation resource and energy requirements if such programs are implemented.

The RIRP will also consider potential contributions of a merchant power market, where energy needs could be partially met by tenders from the Railbelt G&T entity for a portion of the power supply needs. The RIRP process will analyze a range from 0% to 25% of power needs being supplied by merchant power suppliers (Independent Power Producers).

The RIRP will also consider a scenario where in 10 years all Railbelt G&T assets will be owned, controlled, maintained, and operated by a single business entity.

Transmission planning for the RIRP will begin with the most recent Chugach and GVEA transmission plans integrated into an overall interconnected grid development. It will be assumed that transmission projects will be accomplished cooperatively with the serving distribution utility whose service area the transmission line must traverse.

The RIRP will consider future industrial loads compared to a baseline load growth (demand and energy requirements) scenario, that assumes Railbelt development without new, heavy industrial high power demand. An evaluation of potential future industrial projects for the Railbelt and of incremental costs identified for increasing G&T capabilities to supply industrial loads will be completed. This will include the Donlin Creek mining projects and the Pebble Mining project as possible grid interconnected loads, as well as a third, undefined but similarly sized industrial project.

Energy in Alaska

Introduction

It is difficult to conceive many human activities that do not in some way depend on affordable, reliable energy. Whether it is providing fuel for our vehicles, electricity and heat for our homes, or energy for the production and transportation of the products we use daily, almost everything we do depends on a constant supply of energy. Inexpensive energy has helped our society create wealth and, as an energy exporting state, is a cornerstone of our economy.

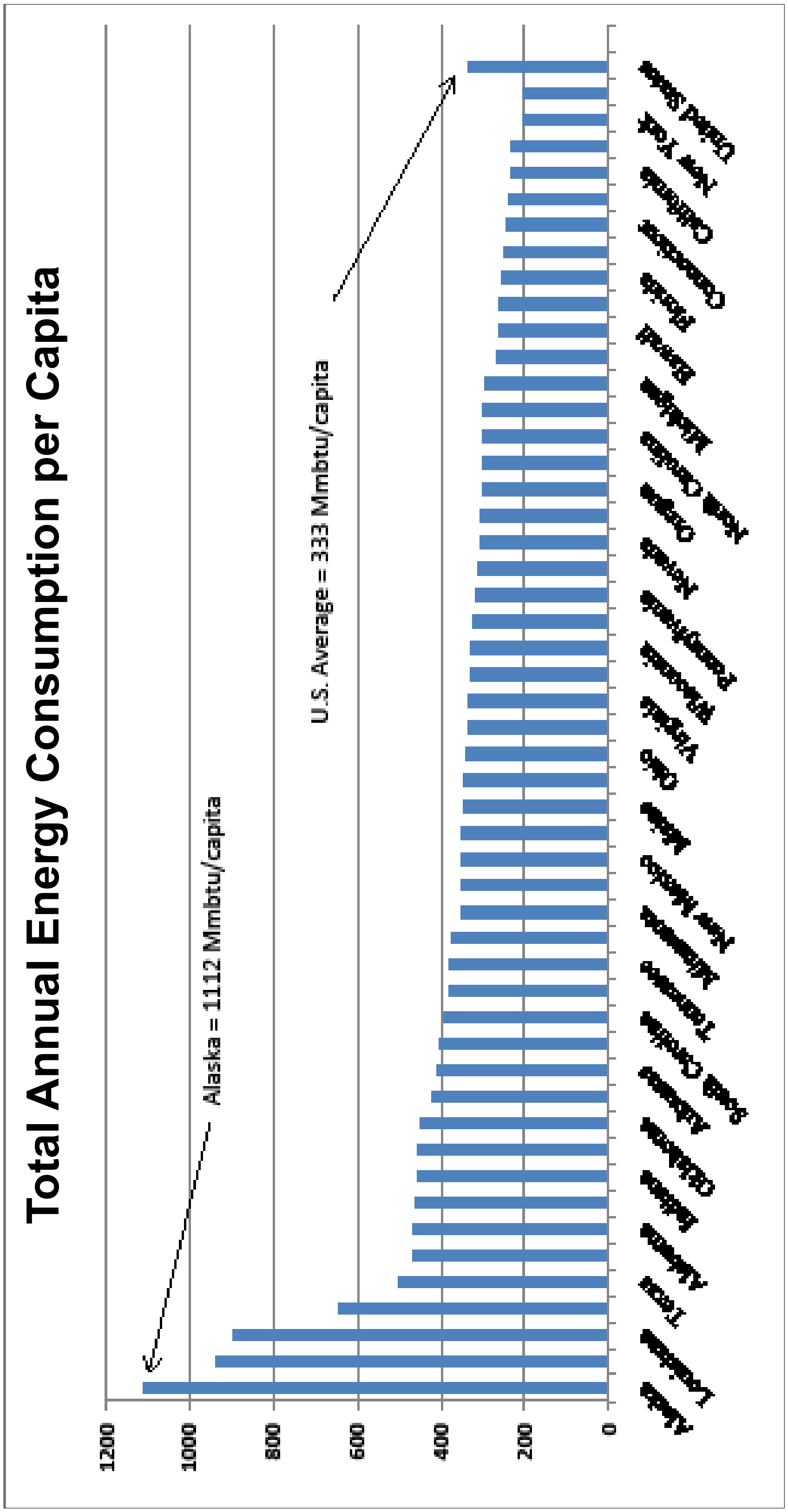
The United States uses more energy per capita than any other country in the world, and Alaska as a state has the highest per capita energy use in the nation at 1112 Mmbtu per person. This is more than three times higher than the national average of 333 Mmbtus, and is in part due to our climate, with long cold winters throughout most of the state requiring more energy for heating homes. However, our geographic location and oil and gas industry also contribute significantly. For example, almost 32 million barrels of jet fuel were used in 2006. Jet fuel constitutes 43% of total energy end-use in Alaska, however a large portion is used for international flights and is not actually consumed in-state. An additional 484 Mmbtu can be attributed to energy used for oil and gas production in 2006, and while this was energy consumed in-state, a vast majority of the product was shipped out of state as crude oil exports.

Alaska is also home to tremendous untapped or underutilized energy resources, including some of the highest concentrations of fossil and renewable energy resources on earth. In addition to the well-known oil and natural gas resources on the North Slope and in Cook Inlet, Alaska's proven coal reserves represent the 4th largest fossil energy resource in the world. Alaska also has significant undeveloped geothermal resources in the Aleutian Island volcanic arc, abundant untapped hydropower, wind, and biomass resources, and the majority of the tidal and wave power potential in the United States.

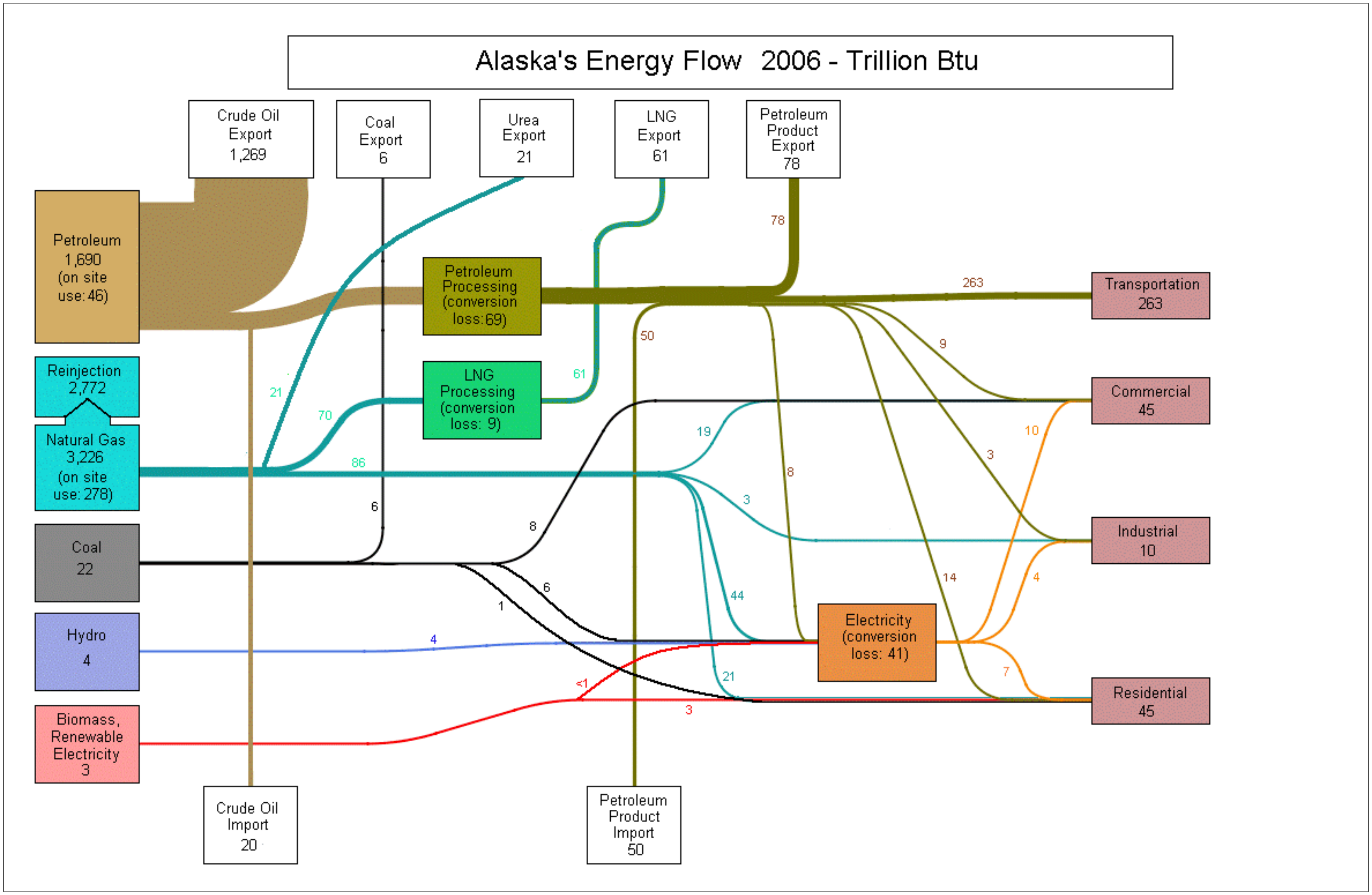
How Much Energy Does the Average Alaskan Use?

A long distance sled dog puts out 5 kW, or 17 Mmbtus, based on a 10,000 kcal/day diet during a typical day on the Yukon Quest or Iditarod. This means that in order to generate the amount of energy needed by each Alaskan every day, we need the equivalent effort of 65 Iditarod sled dogs.

Energy in Alaska



Data from the United States Energy Information Administration (EIA), based on 2006 values.



Energy diagram produced by the Alaska Center for Energy and Power based on data from ISER, the Alaska Department of Natural Resources, the U.S. Army Corp of Engineers, and the U.S. Energy Information Administration

Energy in Alaska

Energy Flow in Alaska

In order to reduce the cost of energy for Alaskans, it is important to understand how energy is produced and how it is used. The energy flow diagram on the opposite page describes the inputs for Alaska energy consumption, as well as the amount used by the residential, commercial, industrial, and transportation sectors. While the values used in this diagram are based on 2006 data, the only recent significant change in major energy use patterns is the closing of the Agrium Fertilizer plant on the Kenai Peninsula, which has eliminated urea exports out of the state.

Energy flow diagrams are useful for visualizing where energy comes from and where it goes. They also demonstrate the inefficiencies associated with various energy conversion technologies as energy is 'lost' between the developed resources (left side of diagram = 2173 trillion btus), energy exports (top of the diagram = 1435 trillion btus), energy consumed (right hand side = 363 trillion btus), and energy imported (bottom of the diagram = 70 trillion btus). This is particularly evident in the production of electricity, where on average 66% of the energy used by our power plants is dissipated as waste heat.

It is also interesting to note that since 2001 (the last time ISER completed an energy flow diagram for the state), residential energy use increased by 18% while the state population increased by only 7%. This shows that we are not doing a good job impelementing energy efficiency measures at the level of the individual home owner, which should be the lowest cost and consequently the first area addressed when seeking opportunities for reducing the cost of energy.

Unfortunately, the picture of energy flow for the entire state of Alaska does little to show what is happening in any particular region, let alone in a single community. For example, a large fraction of the hydropower is produced in southeast Alaska, while natural gas is a large component of energy supply in the Anchorage area and Kenai Peninsula, as well as a few communities on the North Slope. Coal is solely used in Interior Alaska for both power generation and heating.

What is 1 trillion btus?

The units used for the energy flow diagram are in trillion btus (British Thermal Units), where 1 btu is the energy required to raise 1 pound of water 1 degree Fahrenheit. Another way to understand what a trillion btus represents is that each Alaskan uses nearly 1 million BTUs per day; so 1 trillion BTUs is about enough energy for a day and a half of energy use for all of Alaska.

Alaska's total energy consumption in 2006 = 419 trillion btus divided into the following sectos:

- Residential 45 Trillion BTUs
- Commercial 45 Trillion BTUs
- Industrial 26 Trillion BTUs
- Transportation 263 Trillion BTUs

Energy in Alaska

Energy in Alaska

Historical Trends in Energy Consumption

Using data on the consumption of energy from the U.S. Energy Information Administration (EIA), we can track the amount of energy used in Alaska since statehood. These estimates of consumption from the EIA also include energy used during oil and gas extraction processes, and jet fuel from international air travel. The graph below shows the gross consumption of energy in Alaska from 1960 through 2006. Oil and gas production began in Cook Inlet during the late 1960s, and by the early 1980s natural gas was the predominant source of energy used in Alaska. When oil and gas production began on the North Slope in the late 1970s, natural gas consumption by industrial users increased dramatically because it was used to power North Slope operations. All other fuels, including diesel, motor gasoline, jet fuel, and coal, have contributed relatively stable shares of total energy consumption per capita in the state.

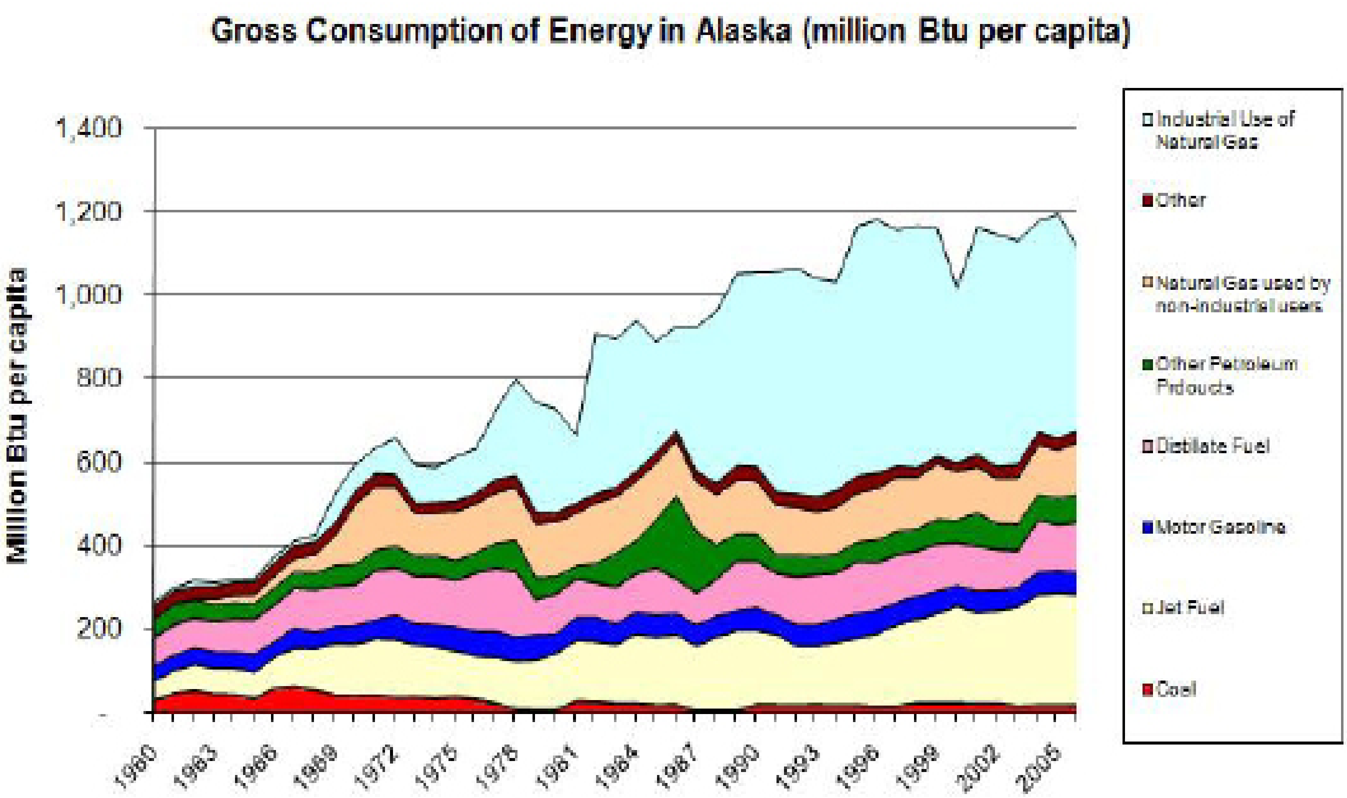


Chart created by ISER based on data from the United Stated Energy Information Administration

Energy in Alaska

Putting the Cost of Energy in Context

While energy and its cost to our communities are the main focuses of this document, the context of energy within the social framework of Alaskan communities must also be considered. Energy is ultimately a tool used to achieve a certain quality of life. Energy heats homes, runs appliances, provides light, fuels our vehicles, and powers communication equipment, among other applications. With this fact in mind it is clear that state energy planning must look at more than simply reducing the cost of energy in communities throughout the state. The planning effort must also look at the much more complex goal of improving and sustaining the quality of life across the state to retain a stable population base, and diversify the economy.

The statement has often been made that many Alaskan rural communities are dying, and this is frequently attributed to the high cost of energy in those locations. It is easy to document the fact that residents in most rural communities spend a disproportionate percentage of their gross income on energy when compared to the more urban areas of the state. According to ISER, in 2006 rural residents spent approximately 9.9% of their total income for energy-related expenses, an increase from 6.6% in 2000, and there has almost certainly been a further increase since 2006.

While this trend is most apparent in rural Alaska, the rising cost of energy is affecting Alaskans in all regions of the state. Southeast Alaska and Kodiak, which largely benefit from stable electric costs from hydropower, are still being effected by the high cost of space heating. The Fairbanks area has seen a dramatic increase in both space heating and electricity costs. Even in the Anchorage area average residential natural gas prices increased 27% in one year, from 2006 to 2007. While the rising cost of energy is clear, what is less definitive is whether these rising costs directly correlate to out-migration from rural to urban areas, and out of the state completely.

ISER recently completed a study that indicates migration from rural to urban areas of the state is a long-term trend caused by a number of factors and that it has been occurring for generations in some parts of the state. There has also been a small net migration out of the state since 2002. Many factors contribute to this trend, including the overall high cost of living in Alaska. In general, people migrate to improve their lives by increasing their access to opportunities such as better paying jobs, education for themselves and their children, and a lower cost of living. It is possible that the current spike in energy costs may serve as a tipping point, or final straw stressing rural residents to the point where the decision to leave is finally made. This decision is also frequently influenced by other considerations: the lack of adequate housing, lack of well paying jobs, and deterioration of social networks due to prior out-migrations and other social issues.

In fact, an attitudinal survey of 600 Alaska Natives and 302 non-Natives who had moved from rural to urban areas of Alaska was conducted by the First Alaskans Insitute in 2007. It indicated that for 65% of survey participants, nothing would motivate them to return to rural Alaska. This is presumably due to a lack of real or perceived opportunities for themselves and their families, which combined with the high cost of living, reduced the overall attractiveness of their community of origin.

In the technology screening database developed as part of this document, the cost-to-benefit analyses of energy projects in each community are based solely on the potential for displacing diesel fuel. There is no consideration included for the impact of any single project on the overall economic health of a community, such as the potential for new jobs, businesses, or industries. However, even though the database does not quantify those impacts, they exist. Examples include jobs created by harvesting and processing wood for a biomass energy project, the development of a greenhouse business based on low-cost heat from a geothermal development project and the stabilization of energy prices through the use of local renewable resources.

An energy project could also have a positive impact on the social health of a community. Examples include a more stable employment base, educational opportunities for local students and the perception that energy prices are becoming more stable. It is usually the communities that already have strong leadership and cohesive social structures that will be most successful in implementing new projects, and those communities tend to be larger.

For more information:

Fuel Costs, Migration, and Community Viability Colt, S. and Martin, S., University of Alaska Anchorage, Institute of Social and Economic Research, May 2008.

Engaging community knowledge to measure progress: Rural development performance measures progress report Alaska Native Policy Center (September, 2007), Prepared for the Denali Commission, available at *http://www.firstalaskans.org/documents_fai/A.%20RDPM%20Report.pdf*

Energy in Alaska

Current Energy Costs and Future Projections

Crude Oil and Fuel Products
Crude oil is a global commodity, and crude oil prices are determined by global supply and demand. Apart from an allowance for tanker transportation costs and quality differentials, it makes sense to speak of the world price of oil. Alaskans can do nothing to impact this price.

There is no price for Alaska crude oil on the New York Mercantile Exchange (NYMEX) or other commodity exchanges. The spot price of Alaska North Slope (ANS) crude oil is calculated by subtracting a market differential from the price of West Texas Intermediate (WTI) quoted on the NYMEX. Four different assessment services estimate that market differential and report a daily spot price for ANS.

Fuel oil (also often called diesel) is one of several products distilled from crude oil and used for heating fuel or engine fuel. Alaskans use a number of petroleum products, including motor gasoline, diesel fuel #1, diesel fuel #2, aviation gasoline, and jet fuel. Motor gasolines are used in automobiles, small boats, and snowmachines; there are typically three grades of gasoline available (mostly in larger communities in Alaska). Diesel fuel #1 is a kerosene product used for heating fuel. Diesel fuel #2 is a light gas-oil used for home and commercial heating and as a motor fuel. Aviation gasoline and jet fuel are used to fuel aircraft, but a type of jet fuel is also often used for home heating. According to Crowley Marine, one of Alaska's largest fuel distributors, most of the diesel fuel in more populated areas like Southcentral Alaska and Fairbanks is ultra low sulfur diesel. Most villages in Western Alaska still use low sulfur diesel because they are exempt from the ultra low sulfur diesel requirement until 2011.

Crude Oil Price Forecast
The U.S. Department of Energy's Energy Information Administration produces long-term price forecasts in its Annual Energy Outlook. The most recent publication was June 2008. In the AEO2008 reference case, the world oil price path reaches a low of $57 per barrel in 2016 and then increases to about $70 in 2030 (2006 dollars).

In the high-price case, with the price of imported crude oil rising to $119 per barrel (2006 dollars) in 2030, the average price of U.S. motor gasoline increases rapidly to $3.06 per gallon in 2016 and $3.52 per gallon in 2030. In the low-price case, gasoline prices decline to a low of $1.74 per gallon in 2016, increase slowly through the early 2020s, and level off at about $1.84 per gallon through 2030 (see Figure 1 on the following page).

It is important to note that in the past, EIA forecasts have not proven to be overly accurate. This is in part because a large number of factors, some unpredictable, can affect crude oil prices on the world market.

Current Crude Oil Price Trends
The EIA also publishes the Short Term Energy Outlook. The next one will be published in January, 2009. According to the October 2008 report, strong global demand and low surplus production capacity contributed to the run-up to record crude oil prices in July. The current slowdown in economic growth is contributing to the recent decline in oil demand and the sharp decline in prices since July. According to the December 8 report, the current global economic slowdown is now projected to be more severe and longer than in last month's Outlook, leading to further reductions of global energy demand and additional declines in crude oil and other energy prices.

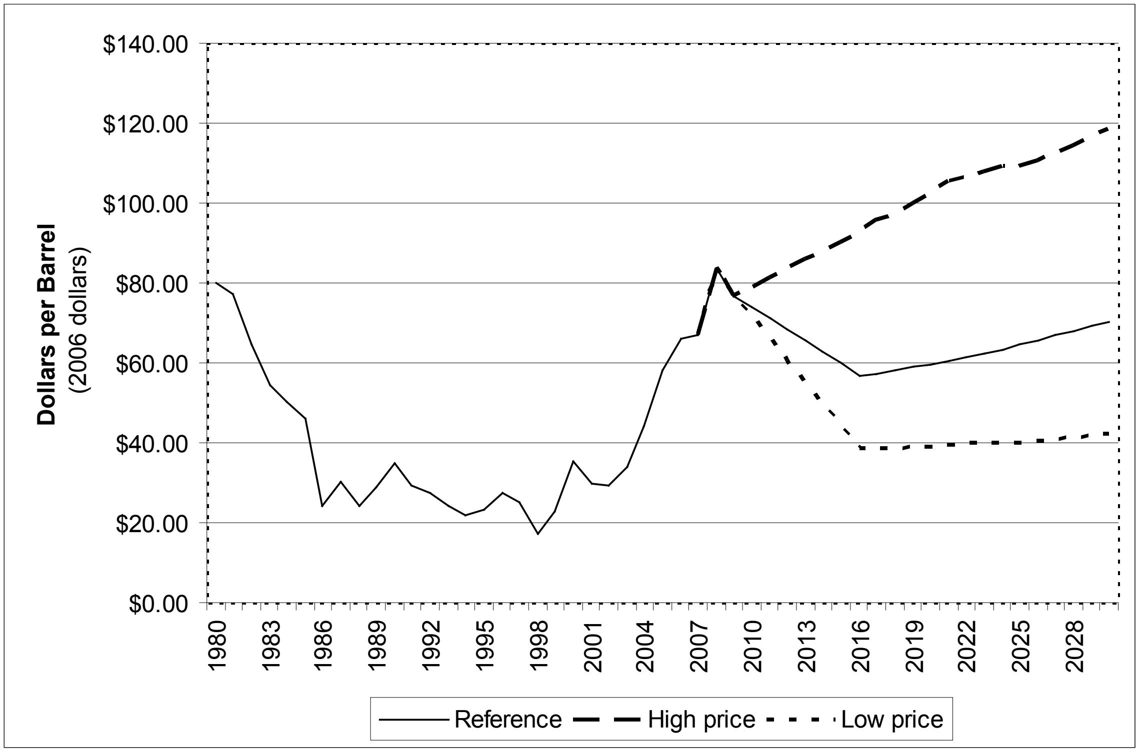


Figure 1. Energy Information Administration Crude Oil Price Forecast

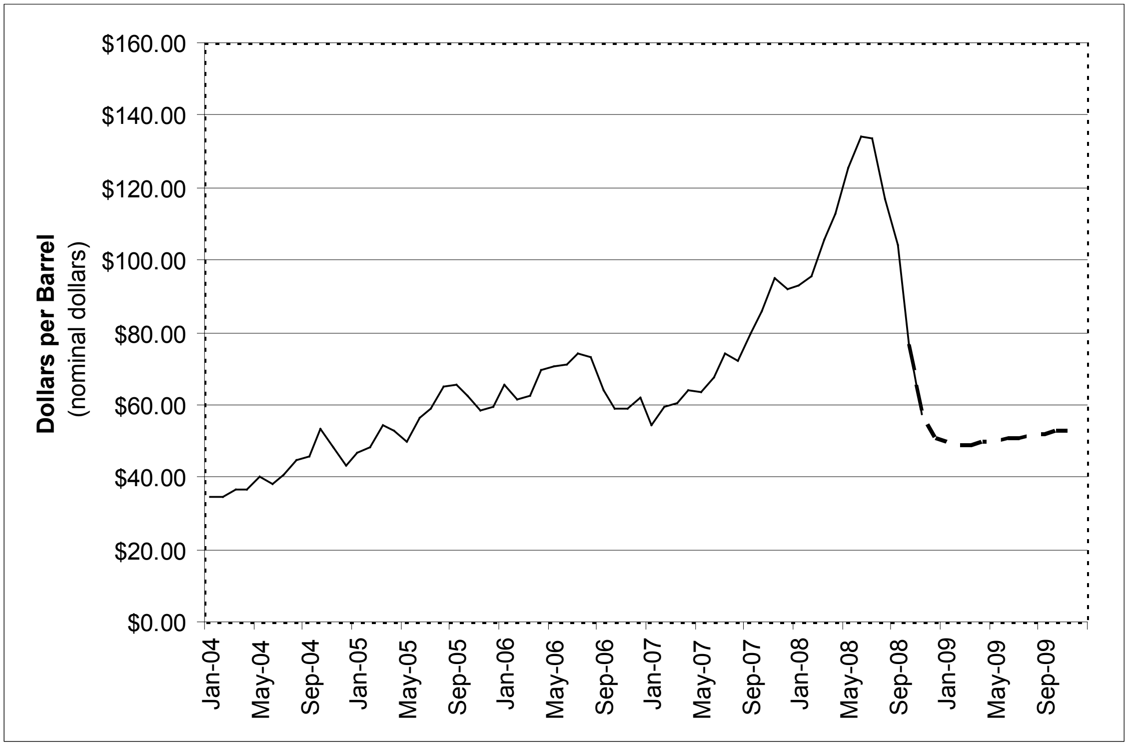


Figure 2. Energy Information Administration Short-Term Crude Oil Price Forecast

The monthly average price of West Texas Intermediate (WTI) crude oil has fallen by more than half between July and November, reflecting the fallout from the rapid decline in world petroleum demand. The annual average WTI price is now projected to be $100 per barrel in 2008 and $51 in 2009. The OPEC oil cartel met on December 17, 2008 and agreed to reduce production by 2.2 million barrels per day, their largest decrease ever, to boost prices. Whether all producers adhere to the reductions and whether the reductions stem the price slide or raise prices are yet to be seen. Figure 2 on the previous page shows the EIA short-term price forecast.

History of Energy Policy in Alaska

Alaska has a history of energy planning and policy development dating from statehood in 1959. That history still holds some relevance today by demonstrating both successful and less successful energy program implementation. This section provides a brief synopsis of past efforts in energy planning and implementation of those plans, including some of the lessons learned.

Overview of Rural Energy

Although electricity first appeared in some rural Alaska villages as a result of military, cannery, mining, or logging operations, its introduction into many villages began only in the late 1950s as the BIA installed small generators for lighting its schools.[1] This electricity was not available to households, and few villages had central power supplies before the mid-1970s. The exceptions were larger rural communities such as Bethel, Nome, Dillingham, and Kotzebue.

Electrification began to spread more rapidly in the 1970s, but an estimated 85 rural communities, most with less than 200 residents, were still without central power supply systems in 1975. Over the next 10 years the state provided local communities a large number of grants for electrification, and by the mid-1980s most remote communities had centralized diesel power facilities.

The demand for diesel and other petroleum products in rural Alaska originated with the introduction of outboard motors in the 1940s and snowmobiles in the 1960s. This demand expanded when the BIA and Alaska State Housing Authority began constructing conventional western housing in rural communities in the 1960s. Demand for petroleum products has continued to expand with the introduction of electric utilities and other infrastructure such as schools and water treatment plants.

Today most rural communities generate electricity with centralized diesel systems. Petroleum fuels provide the bulk of all energy for electricity, space heating and transportation. Costs are high due to the expense of moving fuel to rural Alaska and the small scale of operations. The high costs have motivated residents to use less and mean rural energy consumption is lower than in urban areas.

Rural Energy Policy 1979-1985

In 1979, under Governor Jay Hammond, the state articulated its first energy policy that included the following principles:

1) *Equitable distribution* of Alaska's energy wealth
2) *Improved efficiency* of production and delivery
3) *State planned and funded* facility construction
4) *Technical assistance* in conservation and management
5) *Support for development of locally oriented* energy technologies
6) *Public participation and local input* in energy planning decisions

Several conditions at the start of the 1980s heavily influenced development of this energy policy. This included the concept that developing cheap power, primarily through investment in hydropower projects such as Susitna and Bradley Lake as well as various projects in Southeast Alaska, would stimulate economic development. It was also assumed that state revenues from the newly producing oil field at

1. This historic account through the 1990s is partially extracted from Scott Goldsmith, Short (and Informal) Review of Alaska Rural Energy Policy, with Particular Reference to Alternative Technologies, prepared for the Denali Commission, May 24, 1999.

History of Energy Policy in Alaska

Prudhoe Bay could provide the money needed to bankroll these huge investments. The high price of oil and the expectation that it would continue to rise also led to the assumption that there would be no shortage of money. (In 2008 dollars the 1981 price of crude oil was close to $60 per barrel)

Of particular importance to rural communities were the following considerations:

- A way to spread the wealth from oil to all residents would be to make electricity available and cheap for all Alaska communities, including those in the bush.
- The high price of crude oil meant that the price of diesel fuel, the source of most of the energy for rural Alaska, was oppressively expensive - particularly in relation to costs in urban areas. Many urban places were somewhat insulated by existing hydro facilities or by availability of natural gas, which was not tied to the price of oil.
- The fear of oil embargoes gave rise to the idea of self sufficiency of energy supply, which meant the use of locally available sources of energy rather than the use of imported diesel.
- The national initiative to develop alternative energy and implement conservation measures meant that a lot of money from the federal government was available to consider alternative means of providing electricity in rural Alaska.

In 1980 the state began spending large amounts of money collecting data on energy resource availability and energy use, conducting studies of hydro potential and investigating the potential for alternative energy sources, particularly for the state's smaller communities. For example, the 1981 State Long Term Energy Plan (the first of six such plans) described the activities of the newly formed Division of Energy within the Department of Commerce. Prominent was a list of the alternative energy sources (peat, biomass, solar, wind, geothermal, tidal, hydrogen, fuel cells, heat pumps, and waste heat recovery) that the division would be investigating in the hope that some would be appropriate for rural Alaska.

By the time the 1982 plan was written, the Division of Energy, together with the Alaska Power Authority, had spent $12.6 million on geothermal, wind, wood, peat, single-ground-wire transmission, waste heat, weatherization, organic rankine generators, and tidal energy. The state departments of Transportation and Public Facilities and Environmental Conservation also conducted alternative energy studies. Hydroelectric studies fell into their own category.

The progress of those investigations can be traced through the early 1980s by reference to each succeeding State Long Term Energy Plan. These documents reflect the evolution of policy over time, partially through changes in administrative structure, and tend to be forward looking. Consequently, they include only a limited amount of information about the successes, failures, and lessons learned from money spent on existing projects, including investments in alternative energy.

What Did The State Learn About Rural Energy?
After gaining experience with renewable resource exploration and development in the early 1980s, several conclusions were reached. These included:

Resource Assessment:

- Geothermal resources are site specific and expensive to develop
- Wood is an excellent substitute for fuel oil
- Alaska has vast resources of peat, but technical expertise and infrastructure for its economical use are not in place
- Wind resources need more study
- Seasonal fluctuations restrict the viability of solar power
- Tidal power has limited applicability

Technology Options:

- Diesel generators will remain the dominant option due to their appropriate scale, reliability, and minimal maintenance requirements. Improvements in diesel-operating efficiency offer one promising strategy for addressing the problem of high energy costs in the bush.
- Small hydro and wind projects may be attractive on a site-specific basis. (Thirty-four wind turbines were identified as in operation in 1982)
- Extensive, long-distance intertie systems are probably not economic.
- Fuel cells may prove promising, but they were expensive and not commercial. They have some potential advantages including efficient fuel use, modular design, (theoretically) simple operation, excellent load-following capability, and minimal environmental impact.

The 1983 report, written by Arthur D. Little, found that "generally it is either technically difficult or uneconomic to alter the dependence of Bush communities on oil. Many alternatives, while attractive on the drawing board, experience operation and maintenance problems which quickly negate any cost savings. Reliability and simple technology are therefore essential."

The energy plans for 1984, 1985, and 1986 have less to say about alternative energy for rural Alaska for several reasons. Early enthusiasm for alternative energy sources to generate electricity was dampened because these alternatives did not hold up under investigation either because they were technically or economically infeasible or they did not work in operation. Additionally, and more importantly, the price of oil, and consequently the relative price of electricity generated by diesel in the bush compared to alternatives, was falling. This also resulted in the federal government losing interest in funding alternative energy as the national oil crisis dissolved.

According to the 1986 plan, little progress in energy diversification in the bush had been made since 1979. The only projects that had been implemented were a number of wind generators. In reference to those installations, the 1986 plan concluded that wind power could be both technically and economically feasible and yet still fail because of improper management, logistical problems (distance from suppliers and qualified technicians), or lack of an operations and maintenance network.

1985 Review of Energy Policy

By 1985, concern within the Alaska Legislature on the direction of the state rural energy program led to a review and analysis by the legislature's research agency (House Research Report 85-C). The review concluded, among other things, that:

- State loans and grants to rural utilities for diesel generation systems flourished in the late 1970s and early 1980s.
- Numerous alternative energy demonstration projects were begun in the late 1970s in hopes that they would eventually provide replacements for rural diesel generation.
- The state established a power rate subsidy program in 1980 as an interim measure, until a long-term alternative energy solution could be found for high rural power costs (a.k.a. the PCE Program which is still in place today).
- Disenchantment with the general lack of success of alternative energy projects and the perception of disorganization led to the demise of the Division of Energy and Power Development in 1983.
- As results from alternative energy projects and village reconnaissance studies were made public, many people began to realize there were no realistic alternatives to diesel power generation in many rural communities.

The report quoted one state analyst's perspective on the reasons for the failure of alternative energy initiatives. The analyst's observation was that bureaucracy is not good at choosing winners and losers. The marketplace is better for determining which alternatives are most appropriate. Specific factors the analyst mentioned were: state agencies did not develop strong management capabilities; they lacked methods for assessing the technical and financial feasibility of projects; coordination among state agencies was often lacking; features of an alternative technology were often poorly matched with a useful rural application; unrealistic expectations existed about what an agency or technology could accomplish; and too much responsibility was delegated to contractors while the state often assumed the risk in the performance of the project. When considering the current (2008) RE Fund, the system of competitively and rigourously vetted proposals will hopefully mitigate some of the concerns expressed regarding the failed programs initiated during the late 1970s and early 1980s.

Differing opinions on the role of the state in developing renewable energy projects was also expressed in the 1985 Review. In particular, Neil Davis of the University of Alaska Fairbanks felt that the state had given up too soon on research into alternative technologies, particularly considering the amount of money it was spending to develop other energy resources.

The 1985 Review estimated that from 1975 to 1985 the state had spent $1.7 billion on energy programs. This included $720 million on urban hydro; $93 million for grants and loans for rural electricity generation and distribution; $27 million in the search for alternative sources of energy (hydro, geothermal, coal, and gas); and $24 million in research and pilot projects related to wind, wood, solar, single-wire-ground return, biomass, and waste heat recovery.

The Review concluded that since the state's energy policy was largely driven by the desire to share the wealth from oil, much of the money had not been spent wisely.

Specific criticisms of state energy policy as it was implemented included:

- Most of the focus had been on electricity, which is only a small part of the total energy requirement of rural Alaska.
- Benefits were distributed inequitably, with the better organized communities getting the lion's share of the benefits in a 'survival of the fittest' approach.
- The rural energy problem is not one of high cost, but rather of low cash income to pay for energy.

1990s Energy Policy

In 1986 the state slipped into a recession because of declining oil prices and the state started reducing its budget. Energy policy initiatives were reduced, and most state effort went into the maintenance of existing projects and programs. By the early 1990s the large hydro projects for urban and maritime Alaska and Railbelt interties had been completed, and the Power Cost Equalization program for rural utilities had been established. The Healy Clean Coal Plant was built in 1998, but with the exception of a brief test period, it has not been commercially operated.

Attention in urban Alaska, particularly in the Railbelt, was centered on the introduction of competition in electricity sales, construction of interties, and finding alternatives to Cook Inlet natural gas as it began to decline. State electricity policy for rural Alaska during this period is reflected in the programs of the Alaska Energy Authority, Office of Rural Energy (previously the Division of Energy of the former Department of Community and Regional Affairs).

History of Energy Policy in Alaska

After the large effort that went into wind demonstration projects in rural Alaska in the early 1980s not one of them remained in service by the early 1990s. This was due primarily to immature technology coupled with a lack of continued maintenance as federal tax incentives expired. However, a new generation of improved wind turbine technology began to be tested in Kotzebue, a relatively large rural hub village, and Wales, a very small community. Both communities were using new technology that was more reliable than what was used in the 1980s, and more suited to withstand arctic conditions. Today, Kotzebue is still the leader in wind technology with the most installed capacity of any community, rural or urban, in the state. Kotzebue Electric Association now has twelve 65 kW AOCs, one 100 kW Northwind 100, and one 65 kW remanufactured Vestas. These units currently supply about 7% of Kotzebue's electrical requirements annually.

2000 to Present

State energy policy early in this decade is reflected in the 2003 Statewide Energy Issues Overview, a product of the Alaska Energy Policy Task Force. The Task Force was established under House Concurrent Resolution No. 21 (HCR 21). The sunset date for the Task Force was April 15, 2004. The Task Force examined how electricity is generated, transmitted, and distributed in Alaska in order to meet the State's existing and future electrical needs in a safe, reliable, and efficient manner. It was tasked to develop a long-term Energy Plan for Alaska that would enhance the State's economic future.

For the Railbelt, the primary projects identified were a retrofit to the Healy Clean Coal facility, the Emma Creek (coal) Energy Project near Healy, expansion of the GVEA North Pole power plant, construction of the Sutton-Glennallen intertie, reconstruction of the Anchorage-Kenai intertie, upgrades of military power facilities, and coal bed methane development.

For the Copper Valley, Kodiak, and Southeast Alaska, the focus was on a piped natural gas or propane distribution system to Southeast Alaska, and on interties, including construction of the Swan Lake–Tyee Lake intertie, the Juneau-Greens Creek-Hoonah intertie, and the Kake-Petersburg intertie.

As was true of past state energy policy, the Task Force's work product was primarily focused on electricity and on grants and loans for the construction of new generation and transmission infrastructure.

Concurrent to the Statewide Energy Issues Overview was the development of the 2004 Rural Energy Plan. The Plan recommended a combination of utility management best practices, investments in commercially available, cost-effective production and end-use technologies, and the fine tuning of the power cost equalization incentive structure. It estimated those changes could increase rural energy efficiency by as much as 20% over the next 15 years, compared to current practices. The Rural Energy Plan also suggested investing approximately \$65 million for energy efficiency over five years, an investment the Plan estimated could produce benefits on the order of \$78 million over fifteen years.

The Plan also provides guidance to AEA and the Alaska Village Electric Cooperative (AVEC) for upgrading the following programs: Rural Power System Upgrades, Bulk Fuel Upgrades, Power Cost Equalization (PCE), Alternative Energy and Energy Efficiency, and training. Currently rural Alaska utilities, schools, and residential households account for about \$170 million in annual energy expenditures (utility payments for fuel and non-fuel costs; school payments for heating fuel and electricity; residential household payments for heating fuel and electricity; PCE payments to utilities).

Current Energy Policy and Planning in Alaska

In the last couple of years, attention to energy issues has increased significantly with the dramatic increase in world oil prices, which has simultaneously raised the cost of energy use for Alaskans and swelled state coffers with increased petroleum revenues. After peaking at over $140 per barrel in July 2008, prices collapsed to under $50 per barrel by December 2008. While the price decline provides some relief to urban and ice-free areas of the state, it provides no such relief to parts of rural Alaska that were forced to purchase winter fuel before fall freeze-up. For those communities there is no potential relief until the spring of 2009.

In June, 2008, the Cold Climate Housing Research Center published a report outlining energy efficiency measures that can be implemented as part of the State Energy Plan. The report focuses on programs that address end-use energy consumption in space heating and the electrical needs of residential and commercial users, with a focus on the Railbelt. The recommendations are broken into nine categories. For a more detailed description of those recommendations, please see the Alaska Energy Efficiency Program and Policy Recommendations section of this report or refer to the original document.

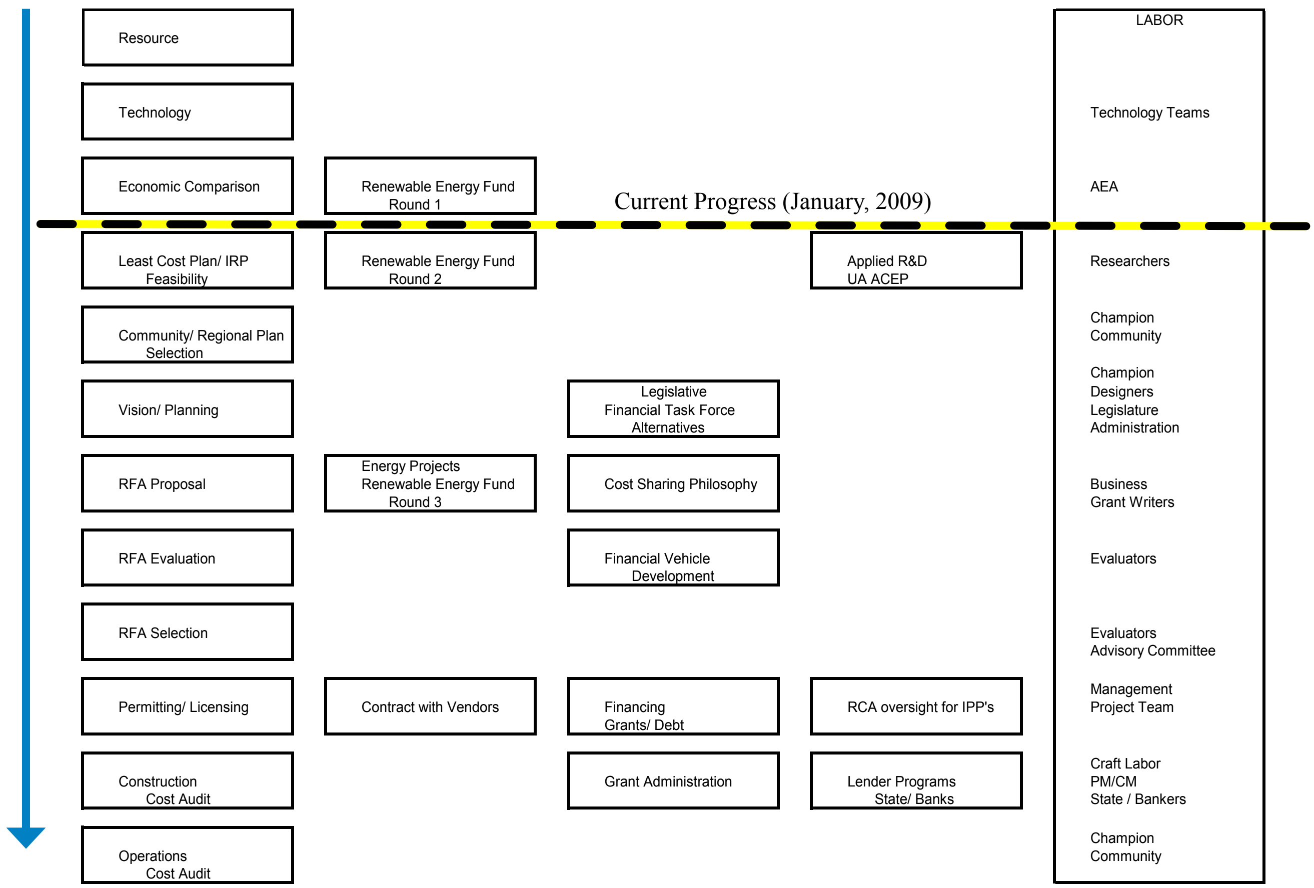
Also in 2008, the Alaska Legislature established the Renewable Energy Grant Program under HB 152, to be administered by the Alaska Energy Authority. The Fund established funding for renewable energy projects over a period of five years at a level of $50 million per year, although each year's appropriation is subject to legislative approval. In 2009, lawmakers approved $50 million to fund the program during the regular legislation session, and added an additional $50 million during a special session for a total appropriation of $100 million available during Fiscal Year 2009.

House Bill 152 also established a seven member advisory board with a mandate to 'consult with the Alaska Energy Authority as it develops eligibility criteria for grants from a renewable energy grant fund, develops methodology for determining the order of projects that may receive grants from that fund, and adopts regulations identifying criteria to evaluate the benefit and feasibility of projects seeking legislative support'.

Summary of proposals submitted under the first round of the Alaska Renewable Energy Fund (2009). This does not include round 2 proposals.

Energy Development Region	Apps/Region	Funding Request
Aleutians	5	$6,155,930
Bering Straits	4	$27,653,406
Bristol Bay	8	$26,093,500
Copper River/Chugach	8	$12,942,225
Kodiak	2	$9,875,000
Lower Yukon-Kuskokwim	10	$20,765,370
Northwest Arctic	9	$29,053,362
Railbelt	20	$129,620,802
Southeast	21	$102,935,093
Yukon-Koyukuk/Upper Tanana	12	$34,425,863
Total	99	$402,111,199

Steps to Successful Implementation of Renewable Energy Grant Fund



Current Energy Policy and Planning in Alaska

Alaska Railbelt Electric Grid Authority (REGA) Study

With recognition of the changing regional conditions facing the Railbelt, the Alaska Legislature recently requested a study to assess whether reconfiguring the electric generation and transmission elements of the Railbelt region would produce benefits in terms of cost, efficiency, and reliability. The contractors for the study evaluated five paths for potential reorganization and tested those paths under four potential scenarios for meeting electric power demand.

The following descriptions of Organizational Paths 2, 3, 4, and 5 focus on the functional responsibilities of a new regional entity. In each case, the new regional entity could be a Joint Action Agency (JAA), generation and transmission (G&T) Cooperative, or State Agency/Corporation.

- **Path 1 – Status Quo.** This path assumes that the six Railbelt utilities continue to conduct business essentially in the same manner as now (i.e., six separate utilities with limited coordination and bilateral contracts between them). It does not include the potential impact of the proposed ML&P/Chugach merger. This is, in essence, the Base Case and the other Paths are compared to this Path for each of the evaluation scenarios considered.

- **Path 2 – form an entity that would be responsible for independent operation of the Grid.** On this Path, a new entity would be formed to independently operate the Railbelt electric transmission grid. Currently, the Railbelt utilities have three control centers (GVEA, Chugach, and ML&P). The operations of these centers are coordinated (but generation is not fully economically dispatched on a regional basis) through the Intertie Operating Committee. This new entity would not perform regional economic dispatch, just the independent operation of the Railbelt transmission grid.

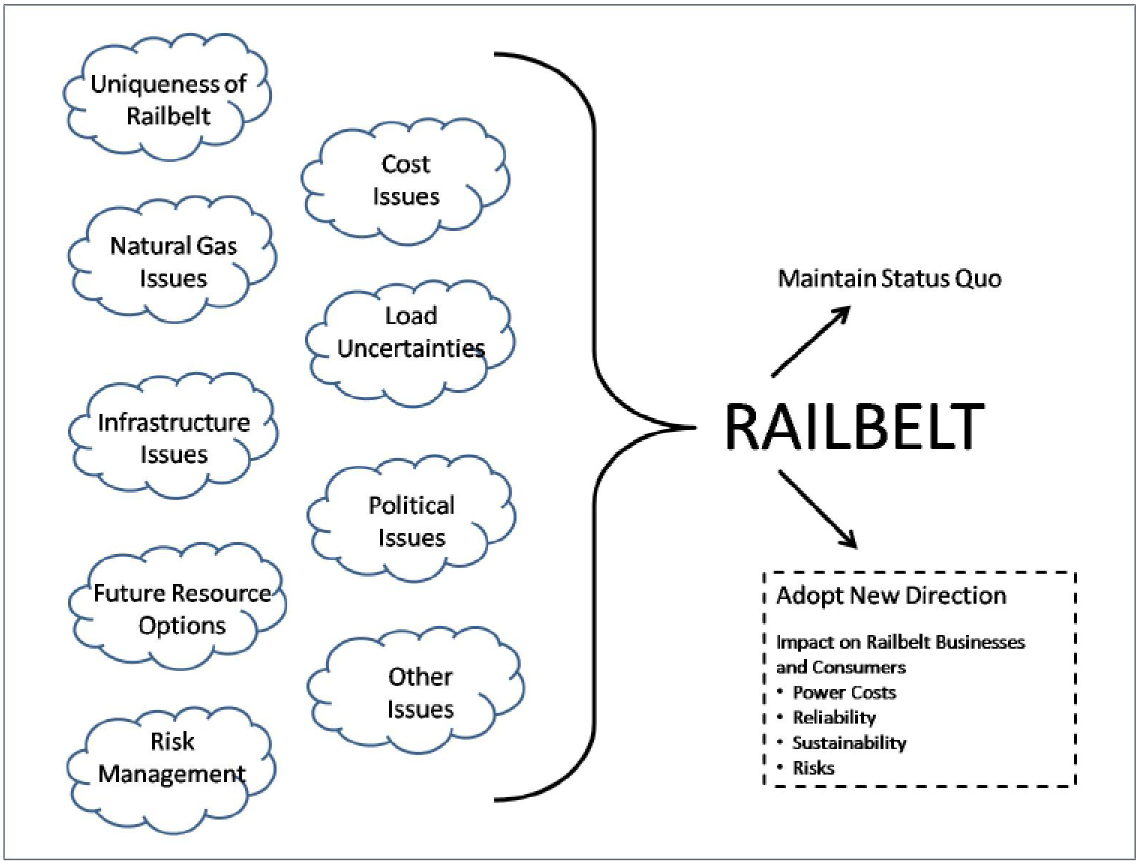
- **Path 3 – Form an entity that would be responsible for independent operation of the grid and regional economic dispatch.** This Path would expand coordination in Path 2 through the formation of an organization that would be responsible for the joint economic dispatching of all generation facilities in the Railbelt. This Path, as well as the following two, will require some additional investment in transmission transfer capability and supervisory control and data acquisition (SCADA)/telecommunications capabilities. This Path, and the following two Paths, would also require the development of operating and cost sharing agreements to guide how economic dispatching would occur, and how the related costs and benefits would be allocated among the six Railbelt utilities.

- **Path 4 – Form an entity that would be responsible for independent operation of the grid, regional economic dispatch, regional resource planning, and joint project development.** This Path is similar to Path 3, except the scope of responsibilities of the new regional entity would be expanded to include regionally integrated resource planning and the joint project development of new generation and transmission assets.

- **Path 5 – Form a power pool.** This entity would be responsible for the independent operation of the transmission grid, regional economic dispatch and regional resource planning. In that sense, it is similar to Path 4, except that the individual utilities would retain the responsibility for the development of future generation and transmission facilities.

The study also considered four potential electric portfolio scenarios to test how, under each, the organizational scenarios would fare. However, the contracting firm reiterated that it was not tasked to choose a generation scenario, and none of the scenarios was based on an in-depth integrated resources plan (IRP). The study concluded that any of the paths could be achieved under any of several potential portfolio scenarios, such as:

- Scenario A – The Large Hydro/Renewables/DSM/Energy Efficiency Scenario assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and demand side management (DSM) and energy efficiency programs.
- Scenario B – The Natural Gas Scenario assumes that all of the future generation resources will be natural-gas-fired facilities, continuing the region's dependence upon natural gas.
- Scenario C – The Coal Scenario assumes that the central resource option is the addition of coal plants to meet the future needs of the region.
- Scenario D – A Mixed Resource Portfolio Scenario assumes that a combination of large hydroelectric, renewables, DSM/energy efficiency programs, coal and natural gas resources is added over the next 30 years to meet the future needs of the region.



Current Energy Policy and Planning in Alaska

State Policy on Criteria for Project Feasibility

Historically, the primary criteria the state has used to evalaute an energy project have been the project's technical and economic feasibility. These are generally still the explicit tests of a project.

Technical feasibility means technically feasible given Alaska's temperature, wind, and other conditions; consequently it is inappropriate to adopt a technology that is technically feasible elsewhere without testing it here. Economic feasibility is usually based on life-cycle costs over 30 years compared to those of the next best alternative, usually diesel when analyzing rural energy projects.

Two other important feasibility criteria for rural Alaska are location feasibility and human resource feasibility. Location feasibility is the support infrastructure in place in the community to deal with the normal but unanticipated situations that arise over the life of a facility. Rural Alaska communities have limited access to an inventory of spare parts or technical expertise in the event of a breakdown. Human resource feasibility is the technical, managerial, and administrative support within the community to take care of the equipment. The importance of location feasibility and human resource feasibility has not yet been documented for rural Alaska electricity projects.

For example, because of today's improved technology wind generation would seem to be an ideal choice for parts of rural Alaska with excellent wind resources. However, wind generation must be used in conjunction with either a diesel system and/or batteries that supply the electricity when the wind is not blowing. Thus a simple solution rapidly becomes more complicated by the need to integrate technologies and operate and maintain them together, and location and human resource feasibility must be considered.

Economic feasibility has consistently been an illusive and controversial topic for Alaska energy projects. This stems from the focus on electric power generation and transmission projects and their tendency to have project economic analyses with benefit-cost ratios below 1.0 (the benefit-cost ratio is equal to the net present value of a project divided by the project's capital cost). This is because of the low price of Cook Inlet natural gas, high capital costs, and limited rate payer market base. The consequence is that projects considered in the 1980s were shelved when oil prices declined, and resurrected during oil price spikes.

In rural Alaska, PCE provides rate relief but unintentionally removes some of the market incentives for local utilities and rate payers to improve the efficiencies of their utilities or invest in energy conservation. Given the small number of rate payers and the high proportion of utility fixed costs, conservation measures tend to benefit the state of Alaska through reduction in PCE payments more than they assist ratepayers and utilities.

A central challenge for both urban and rural project economic feasibility analyses is assumptions regarding future crude oil and thus diesel and natural gas prices. Those prices are at the heart of any comparison of the status quo to alternative projects. A comprehensive review[1] was recently completed on a number of theories of what produced the high price of oil in the summer of 2008, including commodity

1. Hamilton, James D., Understanding Crude Oil Prices, prepared for National Bureau of Economic Research, NBER Working Paper No. 14492, November 2008. This highly recommended paper can be found at: http://www.nber.org/papers/w14492

price speculation, strong world demand, time delays or geological limitations on increasing production, OPEC monopoly pricing, and an increasingly important contribution of the scarcity rent (growth in prices due to scarcity in petroleum reserves and production). The study focused on our inability to forecast crude oil prices. ISER tested the statistical behavior of oil prices, related these to the predictions of theory, and looked in detail at key features of petroleum demand and supply. The study concludes that future oil prices are at best very difficult to predict. For example, using historic oil prices and a first quarter 2008 oil price of $115 per barrel, a prediction of the second quarter 2008 oil price within a 95% confidence interval ranged from $85 to $156 per barrel. Statistically the same forecast projected out four years would give a 95% confidence interval for oil prices being as low as $34 or as high as $391 per barrel.

When investigating the causes of the 2008 price run up, the three key features identified as unquestionably important are the low price elasticity of demand for petroleum products, the strong growth in demand from China, the Middle East, and other newly industrialized economies, and the failure of global oil production to increase. These facts explain the initial strong pressure on prices that may have triggered commodity speculation in the first place. Speculation could have edged producers like Saudi Arabia into the discovery that small production declines could increase current revenues and may be in their long-run interests as well. And the strong demand from emerging economies may be initiating a regime in which scarcity rents, while negligible in 1997, became perceived as an important permanent factor in the price of petroleum.

In other words, all of these factors contributed to price fluctuations and are likely to continue to do so. This suggests that when screening projects for their potential to lower the cost of energy, an average price of oil should be used: over the course of the project's useful life it is likely to be both more and less expensive than its natural gas or diesel alternative. However, scarcity is likely to keep fossil fuel prices trending upward without a significant destruction in world demand.

What is certain is that Alaska's oil production is declining and thus so are future state revenues. Competition for state funding will increase and the opportunity costs of building uneconomic projects will increase. Similarly, the opportunity costs of not completing projects with benefit-cost ratios above 1.0, such as those identified in the 2004 Rural Energy Plan, also increase. Real capital costs for building any projects are also likely to continue to increase with an increase in fossil fuel prices, as commodity prices for construction materials such as steel and concrete trend upward along with oil and gas prices.

Policies with Energy Implications

Fuel Stabilization

The Alaska Power Association (APA), the trade association for Alaskan electric utilities, has hired Steve Pratt to investigate opportunities to stabilize fuel costs. With the recent reduction in crude oil prices an opportunity exists to lock in to these low prices using established financial derivative and hedging transactions to stabilize the net cost of fuel.

The focus of this study was directed to the fuel purchases for electric utilities and school districts as the larger commercial purchasers of fuel in rural Alaska, but could be applied to other fuel use sectors. Essentially, the utilities or school district commits to pay an agreed upon price for fuel delivered at a specific future date – once committed, that price never fluctuates, regardless of what happens to market prices for petroleum products during the interim.

Because this price insurance allows the user to lock into a fixed price, it removes the risk of the fuel price increasing. However, it also removes the cost reduction if fuel drops to a lower price. This is the trade-off of fuel insurance, and is a risk determination that each participant must weigh and evaluate before committing to this program.

Under the APA proposal the program would be governed by an oversight board and administered by the Alaska Power Association. APA would contract for services of a Program Director/Manager who will design, budget for, implement and operate the program, assist and educate participating organizations, and provide continually updated information about the market place risks and opportunities.

This program is designed to provide short-term (rolling 1-3 years) fuel cost certainty for participants. A three-year look ahead position would provide price certainty and allow for accurate fuel budgeting. Predictability of fuel costs will allow the utilities and school districts to tend to the long-term needs of their customers and constituents rather than dealing with the immediate financial crises.

Power Cost Equalization

Since 1980, programs (i.e., Power Production Cost Assistance and Power Cost Assistance) have been enacted by the legislature to assist citizens of the state burdened with high power costs. The Power Cost Equalization program (PCE), which became effective in October 1984, is the latest effort aimed at assisting Alaska consumers faced with extreme electric costs. The PCE program provides economic assistance to communities and residents in rural areas of Alaska where, in many instances, the kilowatt hour charge for electricity can be three to five times higher than the average kWh rate of 12.83¢ (July 2007) in Anchorage, Fairbanks, or Juneau.

The PCE program was established to assist rural residents at the same time that state funds were used to construct major energy projects to assist urban areas. Most urban and road-connected communities were benefiting from major state-subsidized energy projects such as the Four Dam Pool, Bradley Lake, and the Alaska Intertie. To help spread benefits to more remote communities, power cost equalization funds are distributed to eligible utilities, which in turn reflect the state payment by lowering monthly bills to individual customers. The program insures the viability of the local utility and the availability of central station power. The PCE Endowment Fund was created and capitalized in FY 2001 with funds from the Constitutional Budget Reserve and proceeds from the sale of Four Dam Pool Project. The fund was further capitalized in FY2007 with general funds and now totals around $280 million.

Policies with Energy Implications

Eligibility and monthly PCE payment amounts are determined by formula specified in state statute (AS 42.45.110-150). The primary formula variables include:

1) the number of eligible kWh (up to 500 for residential and 70 per community resident per month for community facilities)
2) the maximum per kWh power cost (52.5 cents)
3) the minimum per kWh power cost (12.83 cents)
4) the percentage of actual costs in excess of the minimum, but less than the maximum (95 percent)

A formula is used to determine PCE levels that represents 95% of a utility's costs between the floor (12.83 cents per kWh) and the ceiling (52.5 cents) If the eligible costs are more than 52.5 cents/ kWh, then PCE level is 37.69 (52.5 – 12.83 = 39.69 cents / kWh x 95% = 37.69 cents). The base may vary on annual basis per AS 42.45.110(c)(2).

As a result of increases in the number of utilities participating, changes to the subsidy formula, rising oil prices, and increased population, payments under the program grew from $2.2 million in fiscal year 1981 (FY81) under the power cost assistance program, to approximately $17.7 million in FY87. In FY88, 102 utilities serving 170 communities and 24,455 customers in rural Alaska were eligible to participate. The average disbursement was $686 per customer.

In the late 1980s, AEA expected the PCE program to grow at seven percent annually. As a result, the legislature changed the formula by lowering the number of kWhs eligible per customer from 750 to the current 500 kWh per month. The minimum per kWh power rate floor was also raised from 8.5 cents to 12 cents and was to be adjusted as the average cost in Anchorage, Fairbanks, and Juneau changed. Probably the most significant change from a fiscal perspective was removing commercial consumers from participation in the program. In addition, a mechanism was put in place to allocate dollars across customers if the annual appropriation was insufficient to fully fund the program.

During FY07, approximately 78,500 Alaskans living in 183 communities participated in the program at a cost of $25.4 million. Total utility costs for the period were $142.7 million, so PCE covered approximately 17.8% of utility costs. Despite the growth in the number of utilities and customers, nominal program costs and average disbursements per customer were lower in most years since FY87. This shifted in FY06 and FY07 with rapidly increasing fuel costs. In real dollars, program costs and per customer disbursements have declined.

The PCE program only pays a portion of approximately 30% of all kWhs sold by the participating utilities, and household electricity usage is lower in PCE communities.

Average kWh Usage per household	
PCE communities:	412 kWhr
Anchorage:	725 kWhr
National Average:	750 kWhr

The Regulatory Commission of Alaska determines the PCE level for each utility based on fuel and non-fuel expenses such as salaries, insurance, taxes, interest and other reasonable costs. AEA administers the PCE fund based on appropriation by the legislature, monthly reports submitted by participating utilities, and eligibility determination.

Policies with Energy Implications

Wind Power and other Alternative Energy Impacts on PCE Rates

According to AEA, rates are affected only if wind or alternative energy generation reduces a utility's costs. While there are no implicit incentives in PCE legislation for renewable energy, there is the economic incentive to keep a downward pressure on utility costs and subsequent costs to customer. The greatest incentive is if customers consume more than the 500 kWh program maximum or if the utility's rate is above or close to the 52.5 cent program maximum rate.

However, because of the state's role in funding PCE, which makes it a de facto ratepayer, the state has an incentive to invest in alternative energy that lowers the cost of the PCE program. In addition to direct financial benefits, alternative energy and energy efficiency displacing diesel fuel reduces the risks of fuel spills and greenhouse gas emissions.

Wind power will not completely displace diesel, but it can reduce fuel consumption. For example, in 2007 Kotzebue reduced diesel consumption by 100,000 gallons, saving the community an estimated $450,000. Kotzebue now gets 7% of its energy from wind and hopes to reach 20% in the next several years. Similarly, the fuel cost per kWh is 25% less than it would have otherwise been in the five communities served by wind projects in Tooksok Bay and Kasigluk.

Ultra-Low-Sulfur-Diesel

In response to health concerns related to chemical and particulate matter in diesel exhaust, the Environmental Protection Agency (EPA) enacted stringent standards for new diesel engines and fuels[1].

EPA rules currently mandate the use of ultra-low sulfur diesel (ULSD) for on-highway mobile sources with diesel engines such as automobiles. Similar rules will take effect for construction equipment, locomotives, boats, and ships, and similar off-highway equipment in 2010. The rule for stationary engines applies to new, modified, or reconstructed internal combustion engines used for power generation and to industrial pumps starting with model year 2011

Under the EPA rules for Alaska, rural areas can continue to use uncontrolled-sulfur-content diesel for all uses and are not required to carry multiple grades of fuel until 2010. However, as of June 1, 2010 all areas of Alaska, rural and urban, will begin the transition to ULSD for highway and non-road, locomotive, and marine diesel fuel.

As noted above, the new EPA USLD rules will not be implemented for all fuels and for mobile, stationary, on- and off-road uses simultaneously. Therefore, compliance can occur gradually in concert with the regulation dates. These would require additional fuel segregation by use, or the shift can be made at the earliest compliance date for all fuel uses to avoid additional storage costs. ULSD is usually more expensive per gallon so there would be higher fuel costs for the one-time shift to ULSD. To determine the lowest cost option for rural households, an analysis was completed[2]. It found that the cost is lower to make one rapid transition, because the cost of segregating relatively small quantities of ULSD is higher than using ULSD for all uses, even before the required transition date for that use. However, the study concluded that even an efficient and rapid transition to ULSD will incur significant costs for rural households in the study area, on the order of $190 per household per year or roughly $16 per month.

1. Much of the following text is taken directly from a report published by the Alaska Department of Environmental Conservation. Available at: http://www.dec.state.ak.us/air/anpms/as/ulsd/cost_rpt.pdf
2. Study completed by Northern Economics

Policies with Energy Implications

Carbon Tax or Carbon Cap and Trade

According to 2005 Energy Information Administration (EIA) figures, Alaska consumes 40% more fuel per capita than any other state and more than three times the national per-capita average. This is due to a number of factors including Alaska's remoteness; cold climate; scattered communities and population; limited road system and resulting dependence on air and ferry travel; status as a major world air cargo hub; and oil production, transportation and refining. As a result, measures to decrease greenhouse gas (GHG) emissions such as cap and trade, carbon taxes, or other remedies can be expected to impact Alaska residents and businesses especially hard.

According to the International Panel on Climate Change, the most important naturally occurring GHGs associated with this phenomenon are water vapor (H_2O), carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). To address these issues, in 1999 the U.S. Department of Transportation the created the Center for Climate Change and Forecasting (CCCF), and numerous investigations into addressing transportations climate change impacts were initiated. According to the U.S. Environmental Protection Agency's Transportation GHG Emission Report, CO_2 accounted for 85% of the radiative forcing effect of all human-produced GHGs in the United States in 2003. This proportion is higher for transportation sources, with CO_2 representing about 96% of the sector's GWP-weighted emissions. In 2003, U.S. transportation sector derived all but 1% of its energy from fossil fuels, 97% of which was petroleum.

According to an Alaska Department of Environmental Conservation (DEC) 2008 report, the principal source of Alaska's GHG emissions is residential, commercial, and industrial (RCI) fuel use, accounting for 49% of total state gross GHG emissions in 2005. Nearly 85% of the RCI fuel use emissions are contributed by the industrial fuel use subcategory, approximately 42%. Based on estimates of emissions from large facilities, the oil and gas industry appears to be a key industrial source of greenhouse gas emissions.

Transportation sources accounted for approximately 37% of the gross GHG emissions in Alaska, with jet fuel consumption the largest share. Commercial aviation accounts for 96% of aviaton's contribution; international aviation as a sub-division of commercial aviation appears to be a large GHG emission source and may account for roughly 60% of the emissions from aviation sources, largely due to the role of international cargo at the Anchorage International Airport. In 2006, NASA and FAA conducted a joint workshop with atmospheric and aviation experts on the impacts of aviation on climate change and priorities for future research. They concluded that the effects of aircraft emissions on the current and projected climate of the planet may be the most serious long-term environmental issue facing the aviation industry.

Alaska Department of Environmental Conservation green housegas emission estimates are given in Million Metric Tons of CO_2 equivalents (MMtCO2e) in Table 1 (on the following page). Industry and transportation account for over 80% of Alaska's estimated GHG emissions. Eity production and residential and commercial uses each account for approximately 7% each.

Table 1. Source Group	$MMTCO_2e$
Electricity Production	
Electricity Production - Title V	2.18
Electricity Production - Non-Title V	1.02
Total Electricity Production	**3.2**
Residential & Commercial	
Residential & Commercial - Title V Municipal	0.012
Residential & Commercial - Title V Other	0.007
Residential & Commercial - Non-Title V	3.881
Total Residential & Municipal	**3.9**
Industrial	
Industrial - Title V Mining	0.017
Industrial - Title V Oil & Gas	15.26
Industrial - Title V Seafood	0.16
Industrial - Title V Other	1.737
Industrial - Non-Title V	7.426
Total Industrial	**24.6**
Transportation	
Transportation - Aviation -Commercial - Domestic	4.59
Transportation - Aviation -Commercial - International	7.65
Transportation - Aviation -Commercial	12.236
Transportation - Aviation -General Aviation	0.2479
Transportation - Aviation -Military	0.2477
Transportation - Aviation	12.7
Transportation - Marine Vessels	2.4
Transportation - On-Road Vehicles	3.6
Transportation - Rail & Other	0.12
Total Transportation	**18.8**
Waste Management	
Waste Management - Title V	0.019
Waste Management - Non-Title V	0.981
Total Waste Management	**1**
Industrial Processes	0.3
Military - Title V	0.97
Agriculture	0.05
Total Gross Emissions	**52.82**

Source: EIA, http://www.eia.doe.gov/oiaf/1605/coefficients.html.

Table 2. Carbon Contents of Fossil Fuels	Pounds CO2 per mmbtu
Petroleum Products	
Aviation Gasoline	153
Distillate Fuel (No. 1, No. 2, No. 4, Fuel Oil and Diesel	161
Jet Fuel	156
Kerosene	160
Liquified Petroleum Gases (LPG)	139
Moto Gasoline	156
Petroleum Coke	225
Residual Fuel (No. 5, and No. 6 Fuel Oil)	174
Natrual Gas and Other Gaseous Fuels	
Methane	115
Flare Gas	121
Natural Gas (Pipeline)	117
Propane	139
Coal	
Anthracite	227
Bituminous	205
Subbituminous	213
Lignite	215
Tires/Tire-Derived Fuel	190
Wood and Wood Waste 2	195
Municipal Solid Waste 2	200

Source: EIA, http://www.eia.doe.gov/oiaf/1605/coefficients.html.

Policies with Energy Implications

In order to reduce greenhouse gas emissions, a national carbon tax or a carbon cap and trade program may be created in the near future. Both systems would effectively increase the cost of using fossil fuels, although the cost of all fossil fuels will not increase by the same amount. The tax will be on the carbon dioxide released when the fossil fuel is used. As a result, low-carbon-intensive fuels like natural gas will be taxed about half as much as coal. (Table 2 on the previous page shows the carbon content of fossil fuels)

A carbon tax or a cap and trade system would increase the cost of using fossil fuel energy, increasing the economic benefits of renewable energy projects. The actual increase of the benefits of renewable energy projects is dependent on the size of the carbon tax and the type of fossil fuel replaced.

Net Metering

Net metering is a policy whereby consumers who own small renewable energy facilities such as wind or solar power systems can use their own generation to offset their consumption over a billing period. They do this by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for the excess electricity they generate. Net metering is currently offered in 42 states plus the District of Columbia. Net metering is being considered by the RCA (Docket R-06-5), and by the Alaska Legislature under (HB 288). Concerns have been raised in Alaska regarding the burden that a mandated net metering program could create for small utilities with high fixed costs and a small customer base.

As an alternative to net metering, Golden Valley Electric Association instituted the Sustainable Natural Alternative Power (SNAP) program in 2004, a voluntary program that links renewable energy producers with other individuals on the GVEA grid who are willing to pay a premium for that power. SNAP producers pay to install their own renewable power systems and feed that power onto the grid. They are paid a premium for this 'green' power by voluntary contributions from other GVEA ratepayers. At the end of 2008, there were 27 renewable energy producers and 574 members contributing a total of $36,120 annually.

Land Use

Land use policy in Alaska is primarily addressed at the local government level and, among other things, can dictate the placement of buildings and homes within a community. Indentifying energy efficient land use policy can be one way to reduce the energy needs of a community. For example, in urban communities, land use policy can promote sprawl by lack of zoning or zoning for single use and low density neighborhoods. This sprawl creates increased dependency on automobile use and results in increased energy use.

In rural Alaska, land use policy can be used to encourage building placement that increases energy efficiency by increasing the potential for and benefits of cogeneration. Building a community facility near a cogeneration power plant enables use of waste heat and reduces the energy lost during the transmission of the heat, whether through hot water lines or through a direct heating loop.

Transportation

The transportation industry is a relatively large sector of the Alaska economy. Tourism and international air cargo are both fuel intensive industries that are part of the transportation sector. Also, the cost of transportation increases the cost of living in Alaska because of the state's remoteness. Alaska is remote from global markets and population centers, and communities and industries are remote from markets and population centers within the state, thus requiring greater use of air transportation. This remoteness increases the cost of getting goods and people to and from the state, making the Alaska economy especially susceptible to transportation energy price increases.

Alaska's transportation policy can affect energy use by promoting either energy substitutes or energy compliments. Energy substitutes would decrease the demand for transportation energy. For example, state transportation policy can be used to reduce the amount of fuel used for transportation by promoting public transportation systems. An example would be a commuter rail line or increased bus service between the Valley and Anchorage that would allow commuters to switch from personal automobiles to far less fuel intense public transport.

Roads, railroads and airports are all energy compliments but it is likely that energy prices and use drive demand for energy infrastructure, not vice versa. It is important understand the role energy plays in transportation and to pursue transportation policy that is responsive to changes in energy markets.

According to John Horsley, Executive Director, American Association of State Highway and Transportation Officials (AASHTO), transportation produces 33% of CO2 emissions with highways producing 72% of transportation's share. Transportation will need to do its part to address climate change. Some of this fuel use reduction will occur through fleet fuel efficiency improvements. Federal legislation passed in 2007 called for increased Corporate Average Fuel Economy (CAFE) mandate of 35 miles per gallon (mpg) by 2020. AASHTO's Vision Report calls for doubling the CAFE standard by 2020 to 42 mpg. Europe today averages 40 mpg versus the US at 21 mpg.

In addition to increasing fuel efficiency, the policy goal is to reduce the vehicle miles traveled (VMT) growth rate by 50% (instead of 2.2% growth annually, reduce VMT growth to 1% annually). A policy combining 35 mpg fuel efficiency and 50% cut in VMT results in highway transportation emissions below current levels by 2030. To reduce VMT, the goal nationally is to double transit ridership from 10 billion to 20 billion by 2030. The highway funding reauthorization is expected to increase transit funding 70% from $10.3 billion to $17.3 billion by 2015. In addition to increasing transit use, federal policy will be directed at increasing walking and biking trips, increasing telecommuting/on-line shopping, and adopting supportive land use policies that accommodate one-third of new development through infill of central cities and older suburbs. Mr. Horsley concludes that one third of transportation's contribution to emission reductions will be shaped by reauthorization investments and policies and two thirds will come from federal, state, and local energy policies, local land use policies, the effect of higher fuel prices, and new technologies.

The Low Income Home Energy Assistance Program

The Low Income Home Energy Assistance Program (LIHEAP) is designed to help low income households offset the high cost of home heating. The State's LIHEAP block grant is administered by the Department of Health and Social Services (DHSS) and the Division of Public Assistance.

Policies with Energy Implications

Prior to the spring of 2008, Alaska operated the federally funded LIHEAP program, which capped income at 150% of the poverty income guidelines. In May of 2008, the State Legislature created the Alaska Heating Assistance Program (AKHAP) for households with income between 150% and 225% of the poverty income guidelines.

In 2008 Alaska provided 13,620 households with LIHEAP financial assistance. The average heating assistance benefit was $756 in 2005. Alaska will receive $23.6 million in Federal LIHEAP funding in FY2009, up from $16.9 the previous year (Campaign for Home Energy Assistance, http://www.liheap.org/liheap%20fact%20sheet/AK/liheap-AK.pdf).

AHFC Weatherization Program

For years the Alaska Housing and Finance Corporation (AHFC) has provided free weatherization assistance to low income households. Households that meet the income requirements are assessed to determine the weatherization measures to be performed on the home. The weatherization improvements are done by one of 15 state designated housing authorities.

In 2008 the State Legislature approved $200 million for the weatherization program, and the program's income requirements were expanded from 60% of median income to 100% of median income. Priority is given to the elderly, the disabled, young children, and families under 60% of median income. A household may not participate in both the AHFC weatherization program and energy rebate program (described in the next section). The tremendous popularity of this program has led to bottlenecks and waiting lists because of a scarcity of trained contractors to do the work, as well as a shortage of trained energy raters.

AHFC Home Energy Rebate Program

The AHFC home energy rebate program assists homeowners in making the best energy-efficiency improvements for their home. The Home Energy Rebate program has no income requirements and focuses on owner-occupied homes. Homeowners pay for certain energy-efficiency improvements and are rebated a portion of the cost for doing so.

To participate, a homeowner pays an energy rater to make an initial assessment of the home. The homeowner completes work on measures chosen from the Improvement Options Report and then requests a follow-up energy assessment. AHFC will issue a rebate for some of the costs of improvement. The amount of the rebate is determined by the points and step increase in the home's energy rating, not to exceed actual expenditures supported by receipts. These rebates are for up to $10,000. The program may also supply a $7,500 rebate on qualified, new 5 Star Plus homes.

Particulate Matter Regulation

According to the Environmental Protection Agency (EPA), Particulate Matter (PM) is a "mixture of extremely small particles and liquid droplets" that can cause health problems when inhaled. Fine Particulate Matter (PM2.5) is less than 2.5 micrometers in diameter. PM2.5 is a product of combustion, primarily caused by burning fuels. Examples of PM2.5 sources include power plants, vehicles, wood-burning stoves, and wildland fires. The EPA recently increased the stringency of the PM2.5 standard by lowering the previous 24-hour standard of 65 µg/m3 to 35 µg/m3.

The U.S. Environmental Protection Agency recently announced that it intends to classify Fairbanks and Juneau as nonattainment areas. This classification will force local officials to respond by restricting the use of wood-burning stoves. Winter inversions often leave the air stagnant, allowing PM2.5 to accumulate in the air. If the level of PM2.5 reaches a certain point, the community will temporarily restrict the use of all woodstoves except those that burn wood pellets. The new PM2.5 regulations could significantly increase the cost of heating in these communities because residents will not be able to rely on low-cost wood stoves.

Renewable Energy Fund

In 2008 the Alaska Legislature established a Renewable Energy Grant Fund through the passage of HB 152. The legislation authorized the Alaska Energy Authority to distribute renewable energy grants and set out procedures to be followed to award those grants. The bill also established a state heating assistance program in addition to the federal heating assistance program, and it established an Alaska Renewable Energy Task Force of legislators.

HB 152 promised AEA $50 million annually for the next five years to fund renewable energy projects. An additional $50 million was authorized during a legislative special session for FY09.

Renewable Energy Fund grants are available to electric utilities, independent power producers, governments and government agencies (eg, tribal councils). AEA may recommend grants for feasibility studies, reconnaissance studies, energy resource monitoring, and/or work related to the design and construction of an eligible project. Grants will be awarded based the following criteria:

1. Cost of energy per resident in the affected project area relative to other areas
2. The type and amount of matching funds and other resources an applicant will commit to the project
3. A statewide balance of grant funds to assure funding is made available for feasible projects in all regions of the State
4. Project feasibility (technical and economic)
5. Project readiness
6. Success in previous phases of project development
7. Economic benefit to the Alaska public
8. Other Alaska public benefit (such as ability to use technology in other parts of Alaska)
9. Sustainability
10. Local Support

Energy Research Fund

At this time, no state funding is available for energy research in Alaska. The Alaska Energy Authority currently has no mandate or capability to engage in energy research. The Renewable Energy Fund legislation does not allow for funding of any emerging technologies, and funding is explicitly limited to projects utilizing proven, existing technologies. This limits Alaska's ability to utilize emerging technologies and become a leader in energy development. It is particularly crippling in a state with very different conditions than are found elsewhere in the U.S. in terms of environment, population density, and the isolated nature of the transmission system.

Applied research is designed to solve existing problems, to develop recommendations that can be used to improve practices, and to help decision and policy makers toward effective choices by defining a clear path forward.

According to the National Science Foundation, Alaska currently ranks 46th among states in terms of funding spent on R&D, and it has no significant mechanism for funding energy research at the state, regional, or local level. The creation of an Alaskan R&D or emerging technology fund would put the state in a better position to receive the increase in federal R&D dollars for clean energy development that President-elect Obama is now proposing.

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Permitting

Given the high cost of fuels and energy across much of Alaska, many new projects to develop local resources will be starting across the state over the coming years. Each of these projects will have its own set of needs and development plans. This information will help agencies determine what authorizations are required for a project to progress from conception through construction to operational phase. The specific permits necessary will depend on many variables, and may come from a wide assortment of agencies. Land owners and regulating agencies have the authority to determine what is needed. The developer has the responsibility to work with them all to aquire the proper permits for the project.

Each project will need site control, which is achieved by specific authorization from the land owner. Projects can be on private, native, municipal, state, or federal lands. Often they cross land ownership boundaries necessitating permission from more than one land owner. Hydrokinetic projects in rivers or in the ocean also require permission from the agency that owns the submerged land. In addition, navigation or other access issues need to be addressed. In Alaska, subsurface owners rights predominate over the surface owner's rights, but impacts on the surface owner must still be addressed. There may be different authorizations for different phases of the life of the project. These authorizations often come in the form of permits, leases, or rights of way with stipulations that govern use.

In addition to site control, the use and activities that are part of the project often require the developer to go through other regulatory processes and obtain further authorizations. These other regulatory requirements may control the use of the land and resources or even the sale of power. There may be requirements for the actual physical construction and operations or for management of the camp for the construction crew. Activities during the resource and environmental assessment stage may require different authorizations. Sometimes permitting requirements for larger projects can be coordinated, but often each agency must follow its own regulatory process. Some authorizations are dependent on others, such as the overall umbrella requirement to first obtain a consistency review under the Alaska Coastal Management Program (when the project is related in the coastal district boundaries). Authorizations for experimental projects are short term in nature and will not carry any preference right, implied or otherwise, toward a long term authorization.

Specific regulations govern how an application and subsequent authorization is treated by the nature of the applicant. For instance, with some authorizations, a licensed public utility may have different process and fee requirements than an independent power producer. This is important to understand as it may have longer term implications in the event that the project developer intends to transfer ownership or operation in the future. If the proposed transferee does not qualify under the same terms and conditions of the original authorization, a totally new authorization process would be required.

Some authorization processes are driven by strict timelines. A majority of the authorizations will take some time to obtain. It is essential that the project developer understand the probable timelines to obtain the necessary authorizations. Entities seeking permits are encouraged to start early by working with the authorizing agencies to reduce the chance of project delays at critical junctures. Many agencies are under large workloads, and it is rare that the agencies can drop the permits they are working on in order to expedite an individual request. Energy projects funded through grants do not guarantee that a project can get all authorizations. Grants do not set agency authorization-processing timelines.

The project developer may need to gather data or conduct studies that will be used to determine the appropriate stipulations on given authorizations. Some of the federal processes require environmental or environmental impact assessments which can take a significant amount of time. Most state and federal regulatory processes require a public process with a chance for the public to provide input into the decision-making process. Most public agencies also have some form of option for affected parties to appeal decisions. Agencies try to make sound decisions that will withstand challenge and thus not delay projects. It is in the project developer's best interest to cooperate fully in providing required information to the respective agencies. Developers need to schedule these resource assessments and review periods into their proposed timelines.

Because of the complexity of the permitting requirements, and the diversity of resource development projects, it is best to start working with the agencies early in order to understand the potential authorizations that are needed and the appropriate timing for applications to be submitted. Professional permitting and project consultants will contract for this type of work and help a developer acquire the necessary approvals. Most agencies have a specific contact who can explain what is needed or provide contacts with the appropriate entities.

The following is a list of some of the agencies that should be contacted to determine issues of land ownership or required authorizations. Many agencies offer a centralized public service center, the best initial contact point. Note that this does not include a list of all the potential land owners, nor does it break down each agency that may require more than one type of authorization.

Alaska Department of Environmental Conservation
Alaska Department of Fish and Game
Alaska Department of Natural Resources
Regulatory Commission of Alaska
U.S. Army Corps of Engineers
Bureau of Land Management
U.S. Coast Guard
U.S. Environmental Protection Agency
Federal Aviation Administration
Federal Energy Regulatory Commission
U.S. Forest Service
U.S. Fish and Wildlife Service

Whether project developers are operating in the Coastal Zone or not, two websites provided by the Division of Coastal and Ocean Management under the Department of Natural Resources provide helpful information and diagnostic tools for determining when various agencies should be contacted.

Additional Resources
Coastal Project Questionnaire: http://dnr.alaska.gov/coastal/acmp/Projects/pcpq3a.html

Agency contacts in regions of the state: http://dnr.alaska.gov/coastal/acmp/Contacts/PRCregcont.html

Diesel Efficiency and Heat Recovery

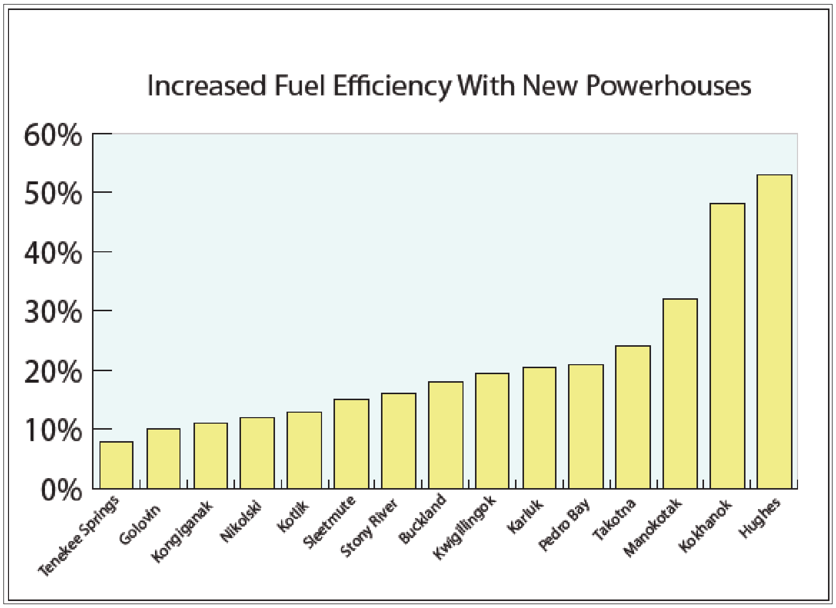
AEA Program Manager: Lenny Landis (771-3068)

New Powerhouse in Tuluksak.

New generators in Tuluksak.

TECHNOLOGY SNAPSHOT: DIESEL EFFICIENCY	
Resource Distribution	Most rural Alaskan communities generate the major portion of their power with fuel oil
Number of communities impacted	Nearly 180, consuming more than 2,500 MWh of electrical energy annually
Technology Readiness	Commercial
Environmental Impact	Reduction of fuel use and related emissions
Economic Status	Typical payback of 3 to 5 years depending on technology used and specific application per community

Rural Alaska relies heavily on diesel engine technology as the main energy source for producing electricity. This reliance is not likely to change significantly in the immediate future. Hybrid and standby diesel generation is still required to augment almost all rural renewable electrical energy sources. In addition, the development of renewable and alternative energy sources for the production of electricity is typically a multi-year project, while diesel efficiency can usually be implemented in a much shorter time. For this reason, diesel efficiency is one of the most cost-effective strategies with the shortest payback. Diesel efficiency can almost immediately reduce the energy cost burden on rural, grid-isolated, Alaskan communities while renewable and alternative energy resources are developed.

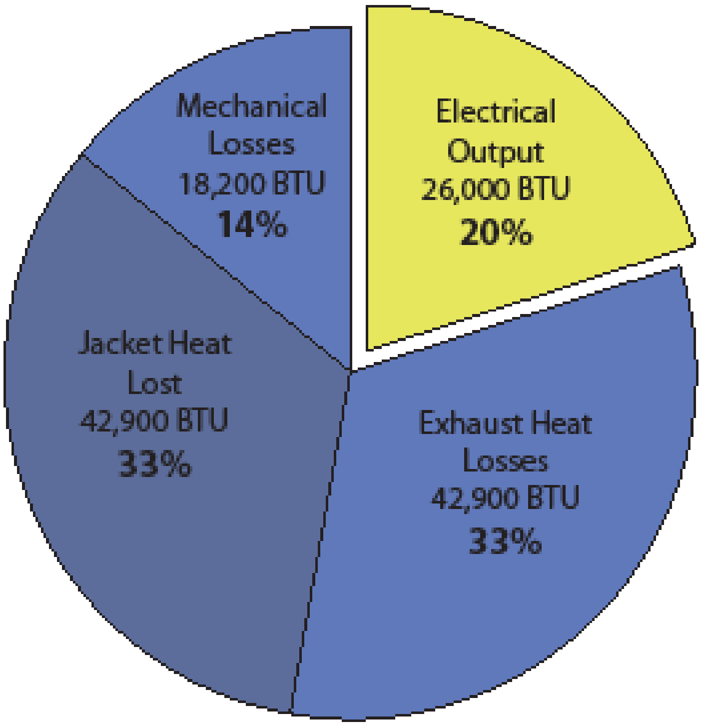


Recent advances in diesel engine efficiency, automated generator controls, heat recovery, and continuous operations and maintenance techniques have made possible diesel fuel efficiency improvements of more than 50% in old, sometimes obsolete, rural powerhouses.

Over the last six years, deployment of modern diesel technology in rural community diesel powerhouses has been documented to increase the usable electrical energy generated from a gallon of diesel fuel by 20% - 30%. Installation of monitored heat recovery systems from both traditional water jacket systems and new exhaust stack heat recovery systems can increase the fuel conversion efficiency of diesel powerhouses by another 20% - 35%. The deployment of automatic, load sensing switchgear with data acquisition and remote monitoring capabilities has lowered the maintenance and operational costs in powerhouses recently constructed by the Alaska Energy Authority (AEA) in rural villages.

The Alaska Village Electric Cooperative (AVEC), with 53 member villages, has also reported similar increases in fuel efficiency as documented by communities that have taken advantage of AEA's Energy Cost Reduction grant program.
The following charts illustrate general estimates of the typical distribution of the fuel energy used in diesel electric power generation.

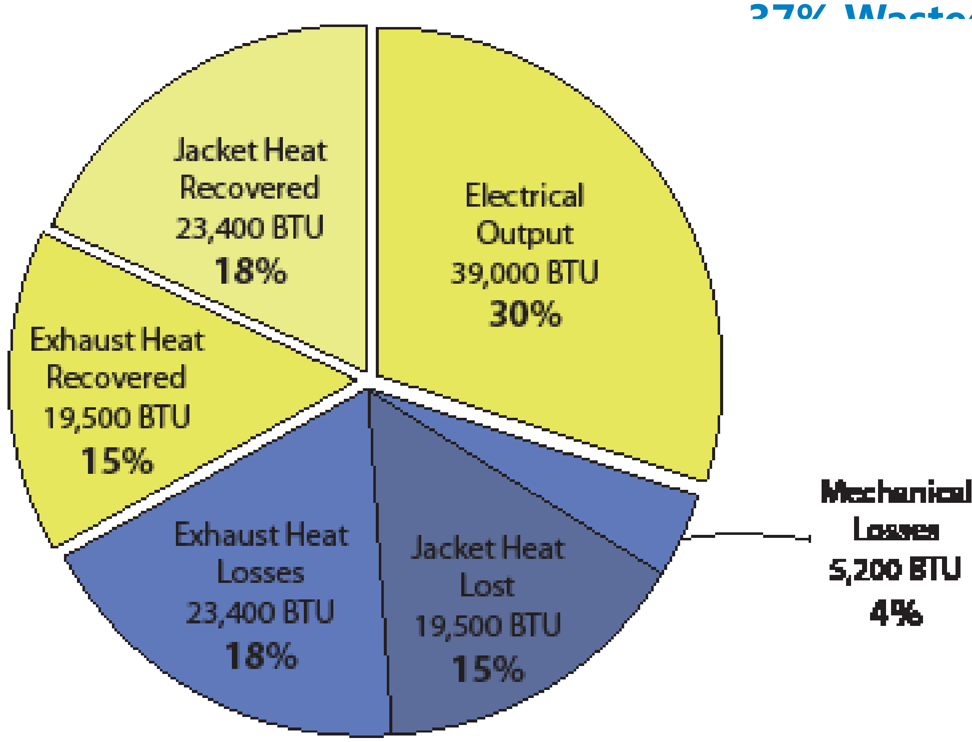
Old Technology



80% Wasted
20% Utilized

New Technology

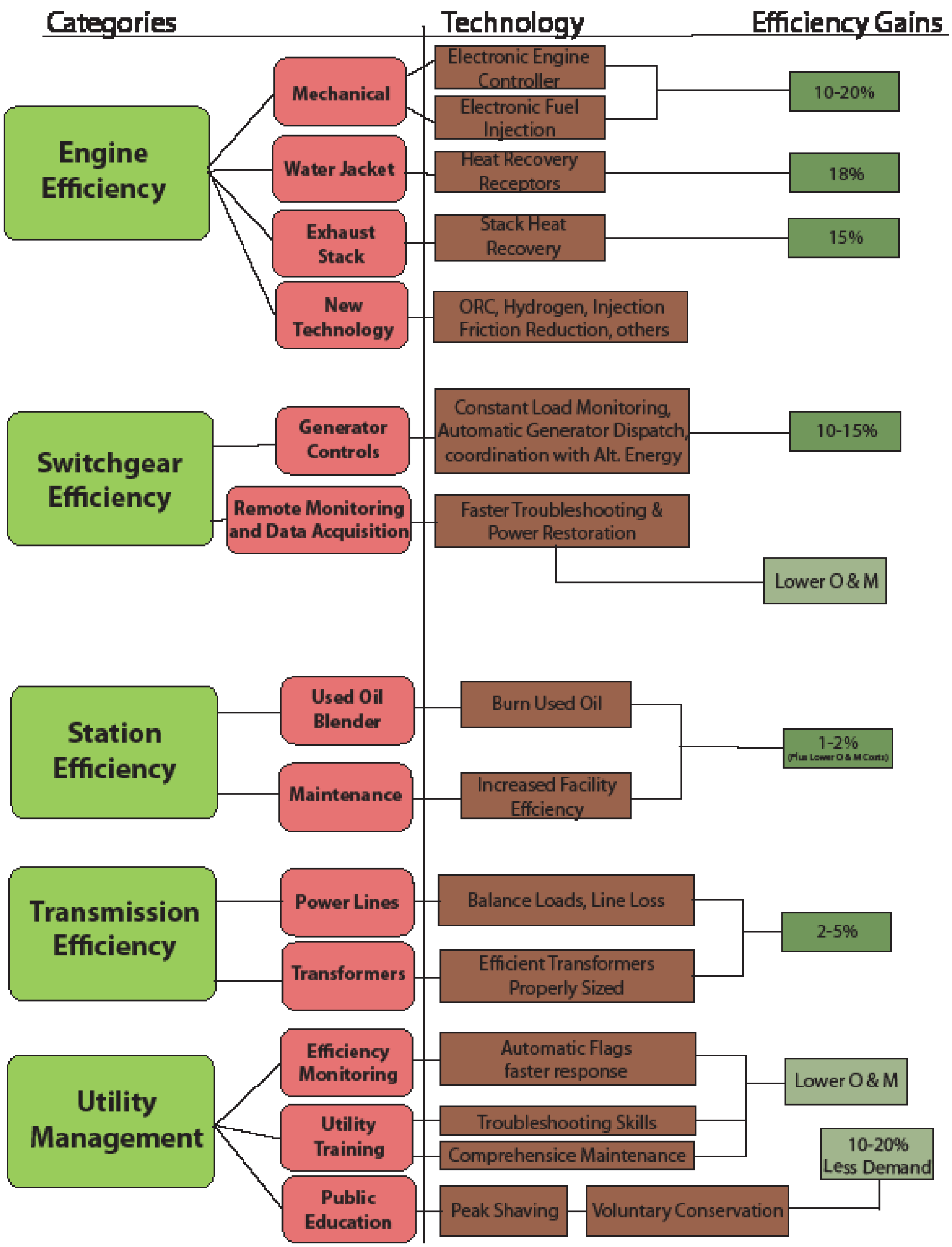
63% Utilized



Increases in diesel generation efficiency can generally be found in three broad areas.

1. Increasing the amount of electricity (kW) produced per gallon of diesel consumed by the generator engine
2. Recovering heat from the engine water jacket cooling system and, if applicable, from the engine exhaust stack
3. Minimizing losses in the electrical distribution system

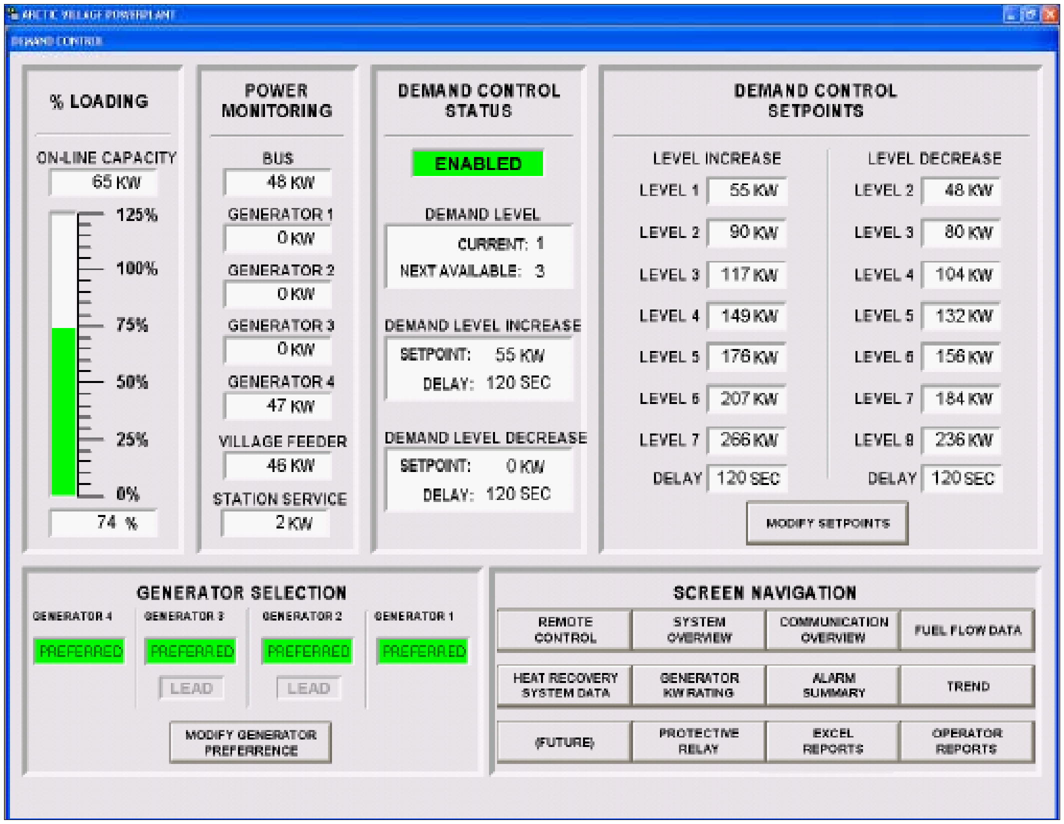
A more detailed breakdown with categories, related technologies, and potential gains is shown in the following graphic.

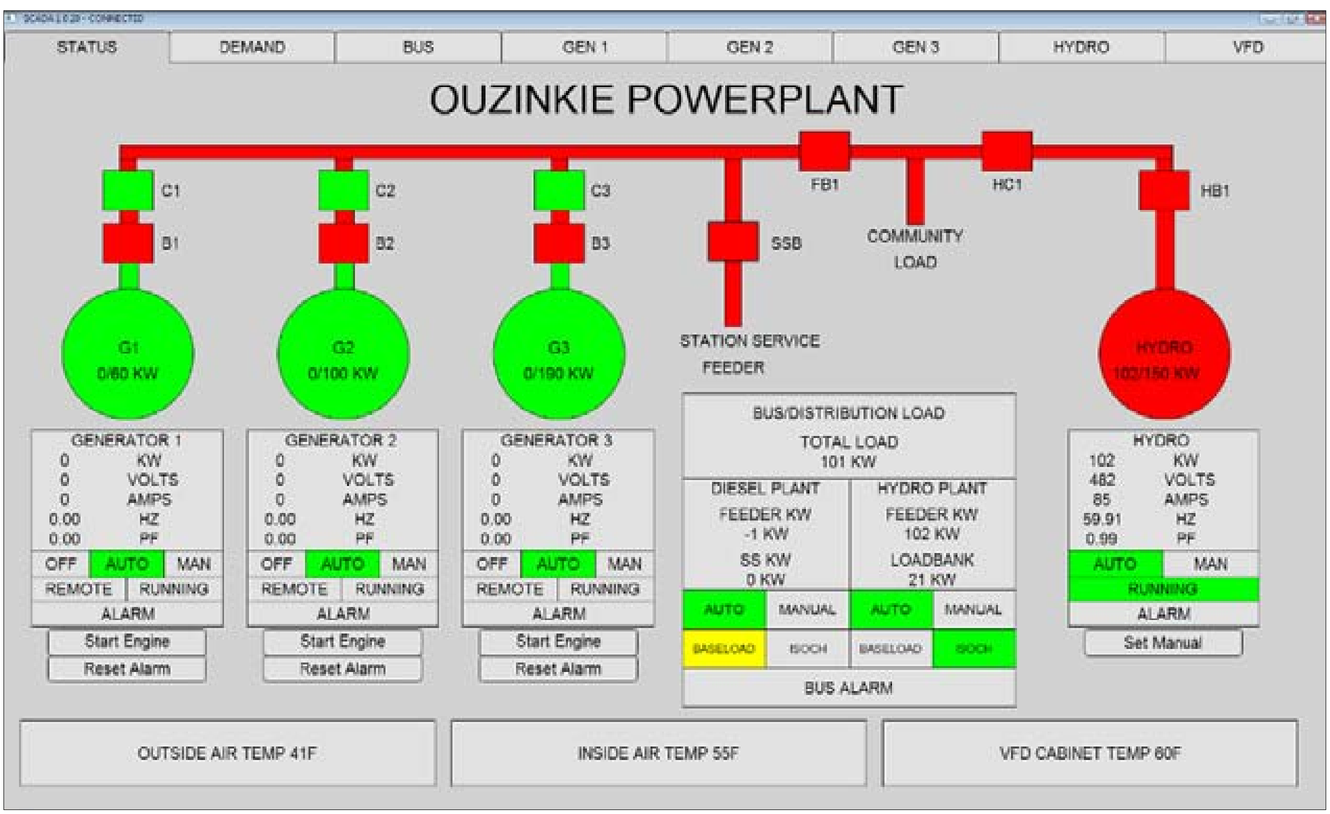


Diesel Engine Controls

Tighter control over the fuel systems provided by electronic fuel injection, electronic speed governors, and electronic engine controllers has boosted the usable kWh per gallon of diesel. Efficiency improvements of 10% - 15% over the older mechanically governed engines have been achieved in over 25 rural powerhouses upgraded by AEA.

Screen images of diesel engine controls.





Powerhouse Switchgear Controls

Advances in powerhouse switchgear control for the automatic dispatch of the most efficient generator or combination of generators to closely match changes in the village load demand throughout the day have allowed efficiency increases of an additional 10% - 20%.

These next two graphics are computer screen captures of the Supervisory Control And Data Acquisition (SCADA) interface utilized in modern powerhouses. Notice that this one is a diesel-hydro hybrid. Programmable switchgear controls facilitate more efficient coordination with renewable and alternative energy sources of electrical power like diesel/hydro and diesel/wind hybrid power systems.

Additional benefits of new switchgear

- Automatic recovery from power outages
- Automatic dispatch of available alternative energy sources
- Data acquisition, historical data downloads for utility planning, energy engineering and research
- Remote monitoring for faster, more efficient troubleshooting

Recently, the reliability and automation of a new diesel/hydro hybrid system was put to a real-world test when an anomaly occurred in a community's electrical distribution system. The hydro was supplying the full community load when a momentary distribution fault tripped the hydro off line in the early morning. Within seconds the powerhouse controls started the diesel generators and restored power to the town. Within minutes the controls restarted the hydro, paralleled it with the most efficient diesel generator, then cooled and shutdown the diesel generator. Without the intervention of an operator and in a short period of time, the community was fully back on clean, efficient hydro.

A significant portion of fuel oil used in rural Alaska is for space heating. Recovery of wasted heat from diesel generation has great economic potential for remote Alaskan communities. Typical applications for heat recovery are environmental space heat for community buildings and augmented electric power generation. The most efficient use of waste heat is to use it directly as heat. This avoids efficiency losses that occur when heat is transformed to another kind of energy. The recovered heat can be used for space heating, domestic hot water, or for tempering municipal water supplies to prevent freezing and facilitate treatment. The efficiency of recovering waste heat for augmenting electrical power production is lower than that for heating; however, it can be attractive and economical in some places since electrical power is needed year round as opposed to space heating, which is usually only needed during the cold seasons.

Heat recovery may use one or all of the diesel generator's waste heat sources including the exhaust stack, jacket water, and charge air. Waste heat recovery using jacket water heat and/or charge air heat directly for heating is a mature and proven technology. Over a quarter of rural village diesel generators have already been equipped with jacket water heat recovery systems. Charge air heat has been recovered for heating in a select number of communities.

Water Jacket Heat Recovery

For rural Alaska, the technologies most applicable are systems that use recovered heat directly, as the end product. Modern high-efficiency heat exchangers, super-insulated heat piping, high-efficiency electric pumps, modern electronic BTU meters, and variable speed radiator fan motor controllers maximize the utilization of heat available from the diesel engines. Waste heat recovery for space heating is a common, proven design. The associated design and maintenance procedures are well understood in the Alaskan power industry. For this reason, water jacket heat recovery for space heating is considered a mature technology in Alaska.

Exhaust Stack Heat Recovery

Heat recovery from the diesel engine exhaust stack is a proven and cost-effective technology in larger power plants. Recent technological improvements have made exhaust stack heat recovery feasible and economical in midsize engines, which are most representative of the engines in rural Alaska. These advances in exhaust stack heat recovery have boosted recovered heat and reduced the hazards and maintenance burdens typical of the older systems. At this time, only one production diesel generator in Alaska, apart from the University of Alaska diesel test bed, is known to employ an exhaust stack heat recovery system for heating applications. This is a relatively large 5 MW power plant at a mining site. No heat recovery performance data for that installation was readily available for this publication.

The reasons why diesel stack exhaust heat recovery is not considered more often in rural Alaska include the high capital and maintenance costs, as well as the potential for excessive exhaust system corrosion and soot build up. The risk of the heat recovery system causing generator failure and higher maintenance costs often outweighs the value of recovered energy. Advances in exhaust heat exchanger design and operational strategies have reduced the probability of corrosion and soot problems. The coming mandate for the use of low sulfur fuel oils will also reduce corrosion risk.

Recently, the University of Alaska Center for Energy and Power conducted an experimental study to investigate the economic effect and feasibility of employing exhaust heat recovery techniques on a midsized diesel engine. Based on the study results, the diesel exhaust heat recovery strategy appeared to cause no critical problems to engine performance nor to increased maintenance frequency.

The payback time for this exhaust heat recovery system is estimated to be less than three years for a fuel price of about $3 per gallon, with engine operation of eight hours per day. Study results and performance of existing exhaust heat recovery systems on large diesel engines in industrial level applications show exhaust heat for heating to be a mature and proven technology, ready for adoption. Performance and economic results will differ for each project. Influential factors, including power plant load pattern, heating load characteristics, and existing heating system infrastructures will also vary accordingly. For this reason, it may be necessary to analyze the specific generating system to be retrofitted, before the installation of an exhaust heat recovery system. As a rule of thumb for rural Alaska, before exhaust stack heat recovery is considered, it is recommended that the diesel generator capacitity exceed 400 kW and that the community have a year-round population above 700 residents.

Heat to Electricity Technology

There are promising methods for waste heat to electric power conversion: organic Rankine cycle (ORC), Kalina cycle, exhaust gas turbine, and direct thermoelectric conversion systems. The organic Rankine cycle and Kalina cycle systems may be preferred because of their availability, ease of installation, and efficiency. For years, engine heat recovery for power generation has been applied to very large power plants and marine engines. Many heat recovery power systems have capacities over a megawatt, including combustion engines powered by natural gas, coal, and petroleum-based fuels.

The performance of the waste power system is relatively sensitive to exhaust temperature and the energy content of the heat sources. For midsized engines, technologies for converting waste heat to electrical power are still in the research and development stage and not yet considered mature technologies. Their feasibility is highly dependent on the fuel cost. Current research and development groups include engine manufacturers and power plant companies. The University of Alaska Center for Energy and Power is also assessing the performance of heat-to-electricity technologies from several manufacturers.

Most existing ORC systems are used in geothermal applications and range in size from about 250 kW to multi-MW. ORC systems for engine waste heat applications have similar capacity. Commercially tested Kalina cycle systems are not common, with only a few in production and almost all of the units in multi-MW capacity. Successful Kalina cycle systems are much larger than a megawatt and would not necessarily scale down to be effective systems on the midsized diesel engines employed in rural Alaska. For many years, small scale, organic Rankine cycle systems were used successfully in some Trans Alaska Pipeline systems. The manufacturer presently produces only large scale systems. Kalina cycle systems based on ammonia are rare, and commercially available options are not of a scale suitable for Alaskan village generators.

The performance of the thermal-to-power conversion systems is sensitive to the properties of heat source, heat sink, working fluid, and energy intensity. For example, resources with similar power capacities may require different systems in order to obtain optimum system performance. Therefore, each prospective installation site will require an individual analysis to insure appropriate operation.

Distribution System Efficiency Upgrades

How the electrical energy is delivered to the load or customer can have a significant impact on the efficiency of the system. The use of newer, more efficient transformers and more flexible power distribution systems that allow easier balancing of the village loads can increase the efficiency of delivered power 3% - 6%.

Electrical loads on the distribution system must be reasonably balanced to obtain the greatest efficiency from the generation system. Loads shift seasonally and annually as new loads and buildings are added or removed. The generation system must be monitored and the distribution system loads adjusted appropriately. Distribution systems may need upgrading if appropriate load shifting adjustments cannot be made.

The voltage of the distribution system can have a significant effect on line losses. An older system design utilizing 208, 480, and 4160 voltages becomes inefficient when the system is expanded to accommodate a growing community's new subdivisions and projects. Newer transformers more efficiently convert between voltages. Power factor can be a significant issue in rural communities where long underground runs have small loads.

Fuel Boosters

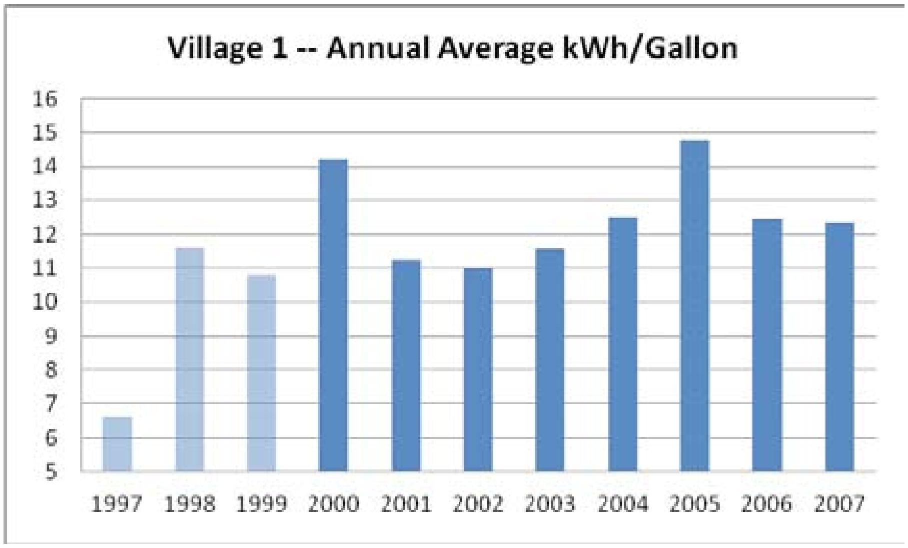
Fuel boosters have not yet been proven under the harsh, varying conditions in remote Alaskan powerhouses. The Alaska Energy Authority suggests test bed studies through the University of Alaska Center for Energy and Power and pilot testing in rural powerhouses.

Operations and Maintenance

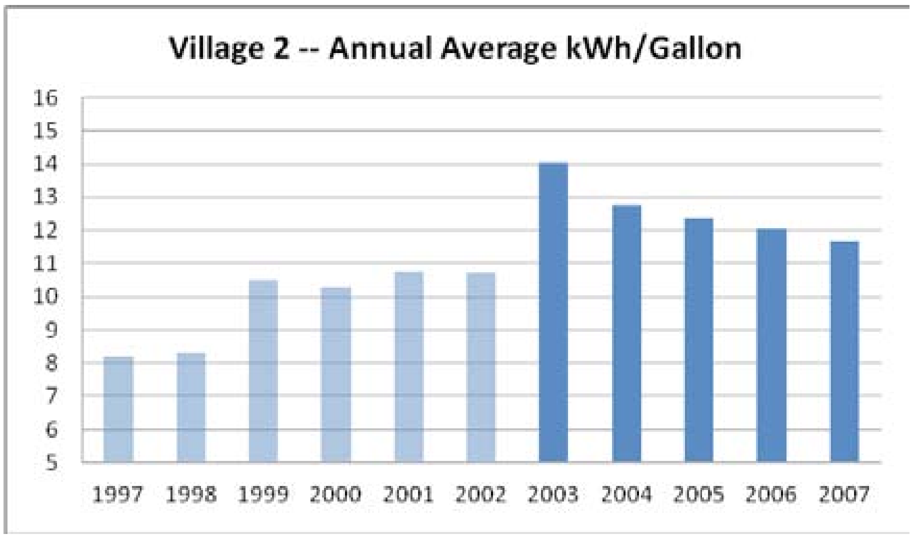
The ability a community has and the methods it uses to maintain and operate its powerhouse have a significant impact on efficiency. Keeping diesel generation systems operational and maintained has a direct influence on the energy produced for each gallon of diesel fuel consumed. Operator training, spare parts availability, automatic system monitoring, data trending, and data analysis, along with prompt maintenance and repair are key factors in keeping efficiency and performance high.

The previous charts document variations in diesel efficiency due to operation and maintenance practices.

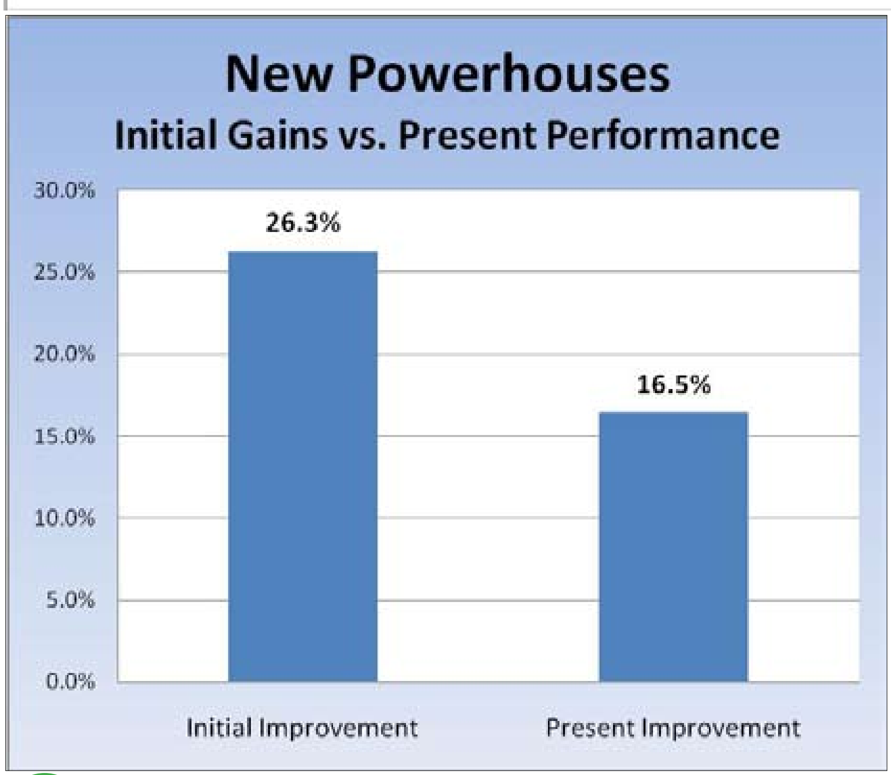
Village 1 received a new powerhouse upgrade in 2000. Efficiency immediately improved from previous years. Notice the decline in the years directly after 2000. This is due to the fact that the utility was unable to consistently operate and maintain the powerhouse. In 2005, maintenance assistance was provided via the Circuit Rider program. Efficiency improved and then again declined when the proper operations and maintenance were not continued.

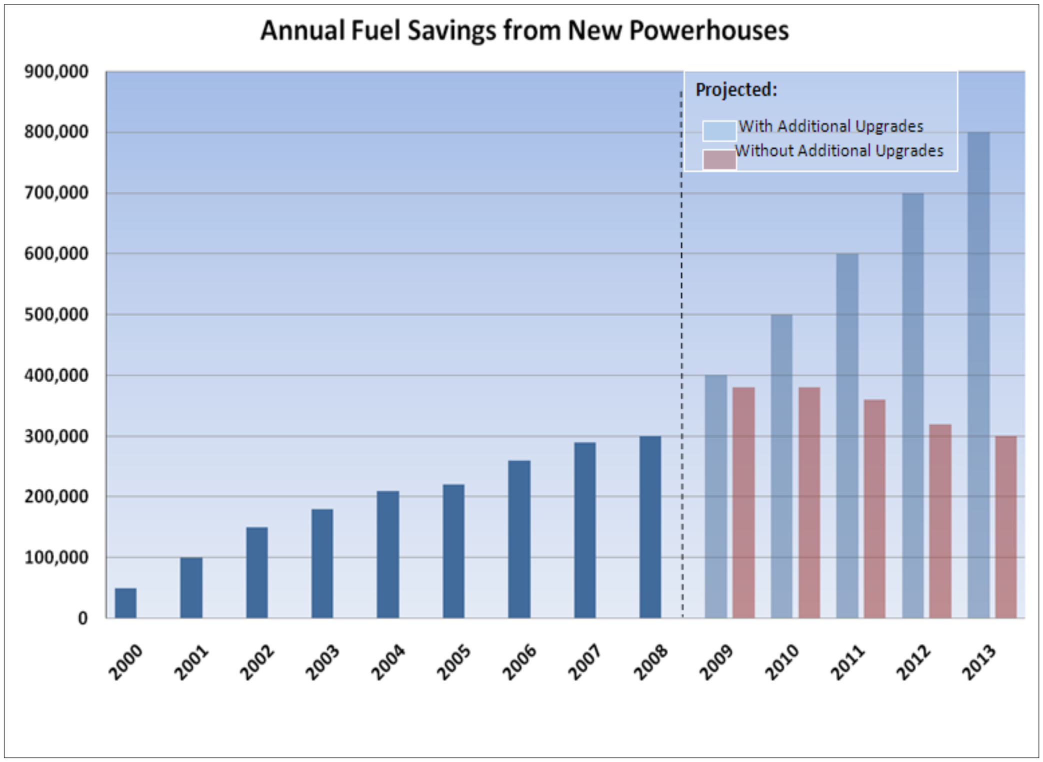


Inconsistent Maintenance (sporadic repairs, generators out of service for long periods).

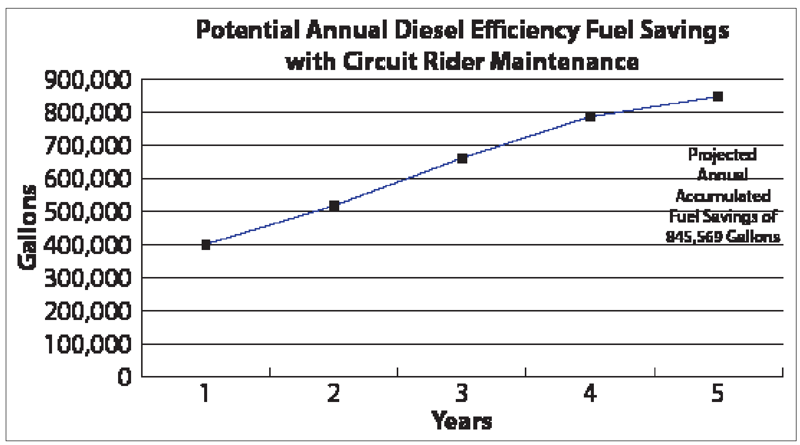


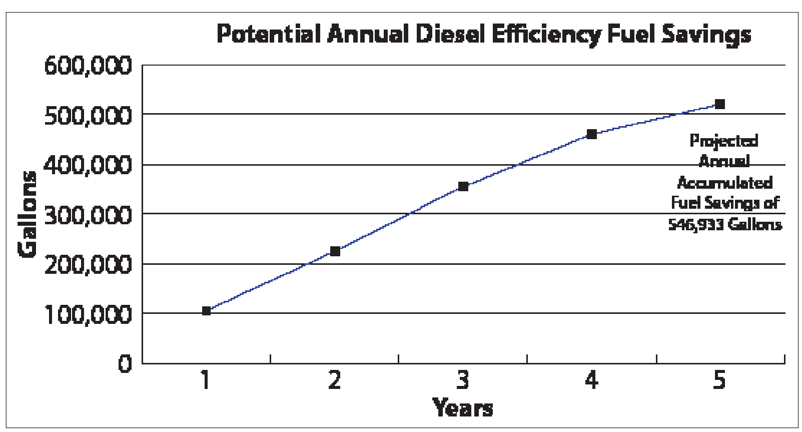
Low Level Maintenance (timely repairs, general engine decline, system de-tuned).





These charts presents the information from a different perspective. Notice the projected loss in savings and efficiency if powerhouse upgrades are not continued and routine maintenance via Circuit Rider is not performed.





This chart presents powerhouse efficiency as a percentage of improvement. The new Rural Power System Upgrade project improved efficiency by >26%. Over time, the powerhouse lost nearly 10% of the improved efficiency from lack of proper routine maintenance.

Improvement to the operation of existing diesel systems is a short-term opportunity for almost every rural community. As such it should be an area of immediate focus. If Rural Power System Upgrades and Circuit Rider maintenance were fully funded across a five year period, a significant amount of fuel oil could be saved. If a portion of the funds from the Circuit Rider maintenance program savings were set aside, local communities or regional associations could continue the Circuit Rider from the reserves, and the efficiency gains could be sustained.
If proper routine maintenance is performed on the 31 powerhouses that have already been upgraded, and if the 62 remaining powerhouses in communities AEA assists are upgraded and properly maintained, over 800,000 gallons of fuel per year will be saved.
Another fuel-saving measure that could be effected immediately is to get existing heat recovery systems operating properly. While a number of Alaskan communities have some type of waste heat recovery system, a substantial number of those systems are not functional. Available records show that if all existing waste heat recovery systems were operational, an estimated 2,917,099 gallons of fuel could be saved annually. Assuming a $3.00 per gallon fuel cost, that translates to over $8,751,298. These numbers are impressive, reinforcing the value of supporting heat recovery systems. It would take only a fraction of this annual savings to get all of these systems back up and running effectively.

Generator Efficiency

Since technologies for increasing the kWh per gallon of diesel burned are mature and commercial generator engine and powerhouse controls are in production, all utilities should consider the feasibility of using them to reduce the cost of electrical power in rural Alaska. Routine maintenance and operations can have a significant impact on efficiency.

Waste Heat

Since technologies for recovering heat from jacket water and exhaust gases are mature and commercial heat recovery devices are in production, all utilities should consider the feasibility of employing jacket water and exhaust heat recovery for heating applications.

Heat to Electricity

More research is needed to evaluate the suitability of organic Rankine cycle and Kalina cycle systems for use in most small Alaska utilities. These technologies may be suitable for use in Alaska's larger power generating plants that operate on fuel oil, but they should first be demonstrated via a pilot project or the diesel testbed at the University of Alaska.

Implementation

The following table provides rough preliminary construction estimates for various types of diesel efficiency upgrade projects in rural Alaska.

AEA's Rural Power System Upgrade (RPSU) program is well suited to rapid implementation of diesel efficiency technologies in rural Alaskan communities. The RPSU program also offers technical and emergency assistance to over 130 isolated, rural villages, and has a longstanding relationship with the Alaskan rural utilities and local native organizations. The program has upgraded 32 rural village power systems over the last eight years, primarily using Denali Commission funding. This program replaces obsolete, inefficient diesel powerhouses with regulatory-compliant facilities that employ new diesel and control technology. These improvements have increased diesel fuel efficiency by 20% - 50%, saving hundreds of thousands of gallons of fuel to date.

With proper funding, RPSU has the resources in manpower, engineering support, and construction management capacity to build five new powerhouses and to upgrade an additional five powerhouses every year.

Diesel Efficiency Project Type	Rough Construction Estimate	Notes
Semiannual Circuit Rider	$5,000 - $15,000	Semi annual on site training and technical assistance
Repair an Existing Heat Recovery System	$25,000 - $50,000	Analyze, repair, upgrade and install BTU meter and monitoring controls
Installation of a SCADA System	$10,000 - $50,000	Remote monitoring capable SCADA system in a satisfactorily functioning powerhouse
Install a Water Jacket Heat Recovery System	$180,000 - $250,000	For suitable powerhouse, modify existing cooling, install heat exchanger, BTU monitoring, and arctic pipe to nearby heat receptor.
Exhaust Stack Heat Recovery	$500,000 - $750,000	For suitable powerhouses with greater than 400kWh average demand and a nearby heat receptor.
Powerhouse Upgrade	$800,000 - $1.2million	Powerhouse structure requires substantial remodel and installation of heat recovery system
Powerhouse Module	$1.2milllion - $1.5million	Retire existing powerhouse and replace with a prefabricated module
Complete Powerhouse	$2million-$3.5million	New powerhouse and heat recovery system with some distribution improvements

Recommendations

The next steps include:

- Identify and correlate funding sources for stable multi-year budget for the program
- Ramp up the current RPSU Program for five plus new powerhouses and five plus upgrades per year
- Evaluate new technologies and support field testing of promising techniques that will increase fuel efficiency
- Add fuel efficiency parameter to evaluation process for new powerhouses
- Reevaluate powerhouses replaced over the last eight years for new technology efficiency upgrades

Case Study

The City of Ouzinkie was able to save substantial amounts of diesel fuel and stabilize its rising energy costs with the combined efforts of community, state and federal agencies. The City of Ouzinkie, Denali Commission, DCCED Community Development Block Grant Program, and Alaska Energy Authority's Rural Power System Upgrade Program all worked cooperatively on Ouzinkie's successful and noteworthy diesel hybrid project.

Before the Project

The City of Ouzinkie has historically been plagued with unreliable power, unpredictable outages, and numerous consumer complaints. Customers routinely replaced damaged electronic equipment and appliances due to power quality problems. The outdated powerhouse equipment was far past its designed useful life. The plant consisted of two inefficient diesel power generators, obsolete manual controls, and an unreliable hydroelectric system. The system required constant operator intervention to maintain a marginal level of operation. The existing powerhouse structure was in relatively good condition and consisted of steel construction with concrete floors. The dam, penstock, and turbine building were in average condition.

The City's water reservoir, dam, and penstock serve a dual purpose. They supply the community with potable water and provide the energy needed to turn the hydroelectric turbine. When the water level behind the reservoir becomes low due to freezing temperatures or low precipitation, the operator must shut off the hydroelectric and revert fully redundant to expensive diesel generation.

The obsolete methodology used for the hydro load and frequency stabilization wasted nearly a third of the potential energy of the hydro. A diesel engine was routinely operated with the hydroelectric turbine to provide backup power just in case the hydro went offline. The trade-off for a small increase in reliability was a significant increase in diesel fuel costs. The diesel generators' sizes were mismatched for community load and for operation with the hydro.

Above: Old Ouzinkie powerhouse. Below: City of Ouzinkie reservoir.

Successful Rural Power System Upgrade for the City of Ouzinkie

Project Scope

The project goal was to stabilize the cost of electrical energy in the community while improving the reliability and safety of the systems. This was accomplished by completely rebuilding the diesel powerhouse and renewing the hydroelectric system. The diesel powerhouse structure was sound, but a small addition of a control room was added for the safety of the operators and the reliability and life of the new electronic switch gear and control equipment. The cooling radiators were replaced and relocated outside. The diesel fuel and cooling piping were consolidated. The old, single-wall, bulk diesel fuel tank was replaced with a double-wall intermediate tank outside the plant. A new day tank with auto fill controls was installed. An automated communications link between the diesel generator switch gear and the hydro facility was established. The turbine and generator were refurbished.

The two old 60kW and 200kW generators were replaced with new 40kW, 100kW, and 155kW diesel generators. All three have automatic paralleling and load sharing capabilities in any combination with each other and with the hydroelectric turbine. The modern switchgear automatically dispatches the most efficient generator.

The new powerhouse switchgear and controls can bring the system from blackout to full diesel to diesel/hydro combination to full hydro. The system will select the most fuel efficient combination of diesel and hydro power all the way to full hydro (diesel off) operation.

Project Result

Though not fully complete, the project has already substantially lowered the community's diesel fuel consumption, increased power reliability and quality, and increased the efficiency of the water resource.

The community's utility manager, Tom Quick, recently reported that last year the community expended over $18,900 in diesel fuel at a cost of $2.76 per gallon. This year they have only spent $4,900 at a current cost of $3.56 a gallon. Port Lions, a nearby community, is reportedly paying over $8.00 a gallon for diesel. Mr. Quick believes that keeping community energy cost stable has prevented egress of the local population.

Recently, the reliability and automation of the new

Above: The City's new powerhouse building.
Below: The new powerhouse equipment.

diesel/hydro hybrid system was put to a real world test when an anomaly occurred in the rural community's electrical distribution system. The hydro was supplying the full community load when a momentary distribution fault tripped the hydro off-line in the early morning. Within seconds the powerhouse controls started the diesel generators and restored power to the town. Within minutes the controls restarted the hydro, paralleled it with the most efficient diesel generator, and then cooled and shutdown the diesel generator. Without the intervention of an operator in a short period of time the community was back on clean, efficient hydro.

Remaining Items

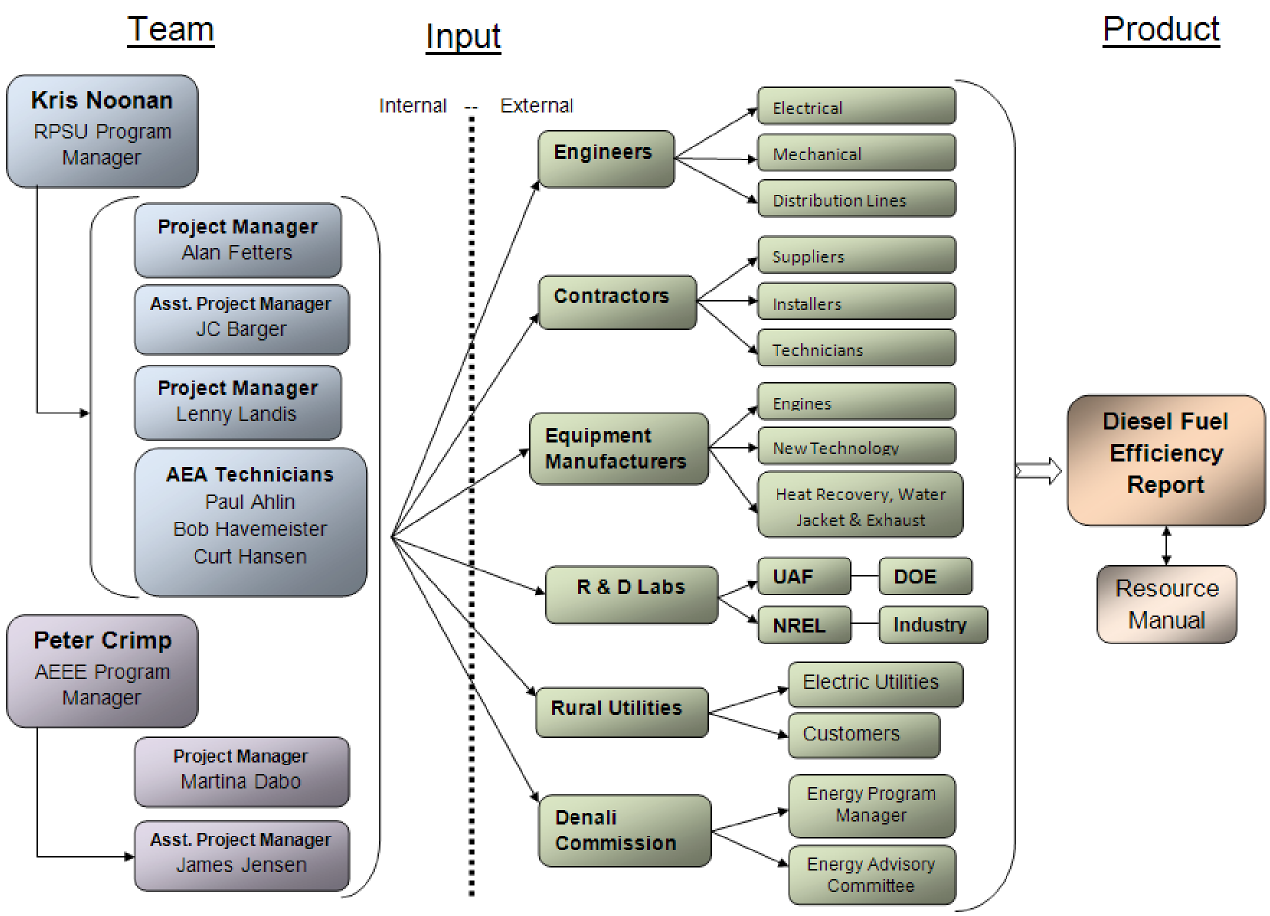
Few items still remain to be completed:
To provide long-term efficiency, reliability, and safety, replacement of the controls and switch gear at the hydro turbine building, addition of a reservoir level sensor and surveillance camera, and installation of a reliable communication link to the dam reservoir. Future plans include waste heat recovery from the diesel powerhouse and electrical distribution improvements.

Continuing Efforts

With the partnership of the Denali Commission and other agencies, Alaska Energy Authority's Rural Power System Upgrade Program continues to assist rural communities to achieve results similar to those of Ouzinkie.

King Cove, Pelican, Gustavus, and Larsen Bay have similar hydro and diesel electric systems. AEA is currently working closely with these communities to maximize their use of renewable hydro resources and minimize their use of diesel fuel.

In June 2008 a Diesel Efficiency Workgroup formed to focus on reducing diesel fuel consumption in rural communities through generation and distribution efficiency measures. The group also reviewed the suitability of available technology for use in rural Alaska, and verified the capital costs and debt service assumptions, along with long term operation and maintenance costs. The structure and output of the task group is represented in the following graphic.



Efficiency (End-Use)

AEA Program Manager: Rebecca Garrett (771-3042)

TECHNOLOGY SNAPSHOT: ENERGY EFFICIENCY	
Resource Distribution	The cheapest unit of energy is the one unused. Increase efficiency and conserve in order to lower the cost of energy.
Number of communities impacted	Resource potential exists throughout the state. Energy conservation and efficiency are ongoing projects that are changing and developing constantly.
Technology Readiness	Mature – energy efficiency requires more mind-set than technology. The most important infrastructure will be an educated public. Education and marketing are valuable components of end-use energy management.
Environmental Impact	End-use efficiency also requires proper design to consider user needs and comfort. Proper disposal of old equipment is necessary. The result is a reduction of energy used, the amount of fuel used, and related emissions.
Economic Status	The rate of return for conservation and efficiency is extremely high. This is a necessary step to take before any kind of new infrastructure is considered. That said, payback depends on energy efficient measures.

This section describes end-use conservation, existing programs to promote end-use conservation measures, and other sources of information on end-use conservation for rural Alaska.

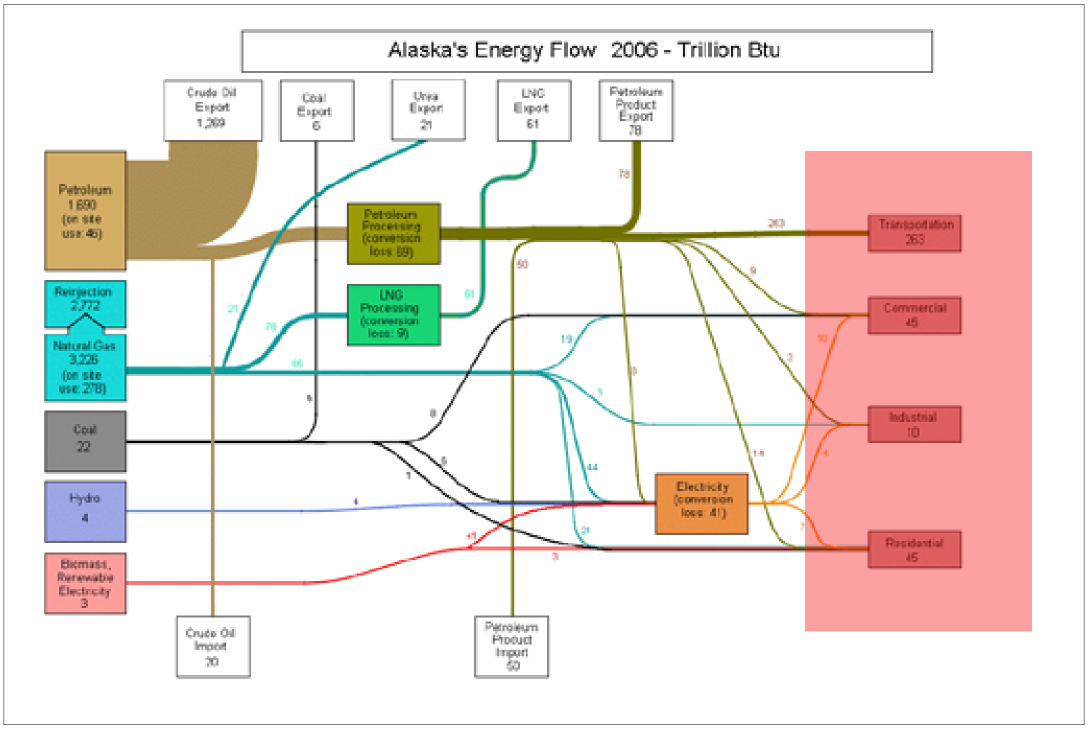
The goal of energy conservation and efficiency is to decrease the amount of energy used, without sacrificing comfort. Examples of energy efficiency policy or best practices are building codes, appliance and equipment standards, and efficiency mandates. Energy efficiency also means operating and maintaining facilities or homes in the most efficient manner, by adding insulation, maintaining boiler systems, or testing the air flow.

Alaska has traditionally focused on energy supply as opposed to efficiency. Many Alaskan communities rely on diesel generation. When diesel prices are low, conservation tends to literally slip out the window.

Energy efficiency and renewable energy are twin pillars of a sustainable energy policy. Becoming more energy efficient is seen as one solution to common, critical problems such as energy security, global warming, and fossil fuel depletion. Good energy conservation policy is primary when addressing these critical issues. The reduction of demands of infrastructure should be the first thing Alaskans do for energy end-use control. This reduction in demand will lead to a lowering in energy supply development cost.

Energy efficiency should be viewed as an investment, in which an initial cost is weighed against a subsequent reduction in expected energy use. Costs may continue to rise, but high costs can be mitigated by energy efficiency. Increased end-use energy efficiency will bring net economic benefits to Alaskan homes and businesses.

Energy conservation focuses on where the energy goes. The red area in the figure below highlights sectors on the demand side of the Alaskan energy flow.



Major Organizations and Programs

The list below provides an overview of entities that promote energy efficiency in rural Alaska.

- Alaska Housing Finance Corporation (AHFC)
  http://www.ahfc.state.ak.us/
- Alaska Energy Authority (AEA)
  http://www.akenergyauthority.org/
- Cold Climate Housing Research Center (CCHRC)
  http://www.cchrc.org/
- Alaska Craftsman Home Program
  http://www.alaska.net/~achp/
- Alaska Building Science Network
  http://www.absn.com/
- Cooperative Extension Service
  http://www.uaf.edu/ces/
- Weatherization Assistance Program Providers
  overview: http://www.alaskacdc.org/
  e.g.: http://www.ruralcap.com/

Table 1: Climate Zones for Alaska

IECC zones for Alaska	HDD[a] Range (IECC)	BEES Climate Regions	HDD[a] Range (BEES)
Zone 6	7200 - 9000	Region 1	7000-10,700
Zone 7	9000 -12,600	Region 2	8600-13,500
Zone 8_{urban}	12,600 -16,800	Region 3&4 – Fairbanks Borough	11,300-17,700
Zone 8_{rural}	12,600 -16,800	Region 3&4 – non-urban Interior, Southwest, & Northwest	11,300-17,700
Zone 9	16,800 -21,000	Region 5 – Arctic Slope	16,900-20,300

Alaska Housing Finance Corporation efficiency programs address residential energy conservation, low-cost loans for energy-efficient structures, technical assistance, and weatherization.

Home Energy Improvement Program

In May 2008 the Alaska legislature appropriated $300 million to AHFC for three programs to help Alaskans reduce energy bills and make their homes more energy efficient. The three programs are:

1. Home Energy Rebate Program
The program allows homeowners who make their own energy efficiency improvements to receive a rebate for some or all of their expenditures. It requires a home energy rater to evaluate homes before and after the improvements. The rebates cover the cost of ratings up to $500 and cover the cost of improvements up to $10,000.

2. Second Mortgage Program for Energy Conservation
The program allows borrowers to apply to AHFC for financing to make energy improvements on owner-occupied properties. If the Home Energy Rebate Program does not fully cover energy efficiency improvements, the Second Mortgage for Energy Conservation program enables AHFC to loan up to $30,000 to qualified borrowers.

3. Weatherization Program
The Weatherization Assistance Program (WAP) enables low-income families to permanently reduce their energy bills by making their homes more energy efficient.
During the last 30 years, the U.S. Department of Energys (DOE) Weatherization Assistance Program has provided weatherization services to more than 5.6 million low-income families.
By reducing the energy bills of low-income families instead of offering aid, weatherization reduces dependency and liberates funds for spending on more pressing family issues. On average, weatherization reduces heating bills by 32% and overall energy bills by $358 per year at current prices. This spending in turn spurs low-income communities toward job growth and economic development.

Residential Energy Efficiency

AHFC also published minimum insulation requirements for buildings in Alaska based on the International Energy Code (IECC) 2006 Sections 402.1 through 402.3. IECC describes the prescriptive method for compliance and establishes minimum thermal envelope insulation requirements for buildings in general. AHFC encourages builders to exceed these minimums. For this reason, AHFC published a list of Alaska-specific amendments to the IECC 2006 and the ANSI/ASHRAE Standard 62.2-2004, Ventilation and Acceptable Indoor Air Quality in Low-Rise Residential Buildings, (ASHRAE 62.2-2004). These amendments shall be limited to new construction only.

AHFC established 5 new IECC climate zones and assigned a zone to each Alaskan community based on heating degree day ranges (Table 1).

Alaska Energy Authority (AEA) promotes energy conservation in Alaska through several programs. As an equal participant in the State Energy Program (SEP), AEA is able to offer small technical assistance grants that help communities get a handle on supply and demand side management and seek funding for implementation. AEA promoted the Village End Use Efficiency Measures Program (VEUEM) and is seeking to implement the Alaska Energy Efficiency Program and Policy Recommendations for the future of their end use programs.

The final "Alaska Energy Efficiency Program and Policy Recommendations" report was completed by Information Insights, Inc. for the Cold Climate Housing Research Center in June 2008. The report was funded by the Alaska Energy Authority and the Alaska Housing Finance Corporation. It is a comprehensive review and analysis of energy efficiency policies and programs in the State of Alaska. With primary emphasis on Railbelt communities, the review focuses on programs that address end-use energy consumption in space heating and electrical needs of residential and commercial users.

The report outlines energy efficiency measures that can be rolled into the Alaska State Energy Plan and implemented immediately. These energy efficiency measures, undertaken at low cost, pay back initial investment in a matter of months or a few years and provide long-term cost savings.

Alaska Rural Energy Plan

The Alaska Rural Energy Plan published in 2004 by AEA identified and widespread opportunities for reducing costs of power and heat. After a preliminary screening analysis that identified end-use efficiencies as a potential source of economic benefits for rural households, Section 4 of the 2004 Alaska Rural Energy Plan examined end-use energy efficiency in rural Alaska households and rural schools in communities that are eligible for Power Cost Equalization (PCE) Funding. The objective of the study was "to evaluate the costs and benefits of end-use energy efficiency systems that are suitable for rural Alaska and determine the extent to which these systems could potentially reduce the cost or improve the reliability of electricity for rural communities" and, to review program implementation alternatives with the goal of maximizing program effectiveness.

Thereby the study distinguished between the engineering economic potential (avoided cost if adopted) and market potential (estimate of participants) of end-use energy efficiency measures. The study makes this distinction to account for the fact that despite extremely favorable engineering economics, customers may not purchase the most economic alternative.

The Alaska Rural Energy Plan also addresses some utilities concern that "in low or no-growth markets with adequate generation capacity, a large investment in energy efficient light bulbs may have adverse effects by noticeably reducing demand and causing generating plants to operate lower on their fuel efficiency performance curve".

As an example, an annual $224 savings per household in rural Alaska could be achieved by switching to fluorescents light bulbs, assuming seven incandescent bulbs that would be replaced with small compact fluorescents.

Village End-Use Energy Efficiency Program

Community impact is exactly what Alaska Energy Authority (AEA) is considering when coming up with the Village End-Use Efficiency Measures (VEUEM) program. Communities are selected based on recently having received or being about to receive a Rural Power System Upgrade (RPSU) or other energy infrastructure project. The intent is to reduce usage and properly size new power systems. This covers both demand and supply side issues.

The village end-use energy efficiency program performs energy efficiency upgrades on rural Alaskan community buildings. AEA, with funding from the Denali Commission, works with villages to help them achieve energy savings by replacing or installing energy-efficient lighting, switch boxes, motion sensors, set back thermostats, weather stripping, and low mass boilers.

The program helps communities to achieve significant progress toward energy efficiency.

In Phase I, the average grant fund per village was $37,771 with a total program grant fund of $642,116. Significant in-kind contributions from the local school districts helped expand the reach of this program. Full Phase I reports can be found here:

http://www.akenergyauthority.org/programsalternativeVEUM.html

The figure below provides a community overview of finished (Phase I, blue) and ongoing (Phase II & III, black & red) projects. Additional communities will be included in the program if funding becomes available.

Case Study: Koyuk

The community of Koyuk participated in Phase I of the village end-use energy efficiency program. In total, 5 community buildings and 7 teacher housing units received energy efficiency upgrades. The city-owned buildings got retrofitted with 93 linear fluorescent fixtures with T8 lamps and electronic ballasts, and seven compact fluorescent light bulbs were installed. The pre-retrofit energy use for all lighting was 14,852 watts. The energy use for all lighting post-retrofit is projected at 10,550 watts. This equals an energy reduction of 29% or 4,302 watts. The estimated annual savings under different assumptions are shown in the table below.

The potential cost savings of energy conservation and efficiency is extremely difficult to get a handle on. During a time of rising fuel costs, efficiency may simply keep costs stable while actually reducing usage. Energy conservation and efficiency should always be looked at in usage numbers as opposed to cash payback.

In small communities, the economy of scale is at stake. If the school is the largest electric user in the community and they reduce their usage by 30%, the utility must still recover their fixed costs from the last fuel delivery and pay for employees. The community may experience a rate increase. However, exploring both supply and demand side efficiency opportunities can reduce any community-wide impact.

Hours Per Day / 250 Days Per Year	Electrical Savings	Avoided Diesel Use	Avoided Diesel Costs
4 Hours	$1,570	315 Gallons	$589
7 Hours	$2,748	552 Gallons	$1,031
10 Hours	$3,926	788 Gallons	$1,473

The "Alaska Energy Efficiency Program and Policy Recommendations" report was completed by Information Insights, Inc. for the Cold Climate Housing Research Center in June 2008. The report was funded by the Alaska Energy Authority and the Alaska Housing Finance Corporation. It is a comprehensive review and analysis of the energy efficiency policies and programs in the State of Alaska. The review focuses on programs that address end-use energy consumption in space heating and electrical needs of residential and commercial users, with primary emphasis on Railbelt communities.

The need for such a report was recognized because demand side management (energy efficiency measures) and conservation are often overlooked by decision makers in favor of supply side solutions, which offer constituents new projects and funding opportunities. The report states that supply side solutions are necessary in Alaska, but efficiency measures should be step one in any energy plan. Efficiency measures are the best way to decrease demand and save money.

The report outlines energy efficiency measures which can be rolled into the Alaska State Energy Plan and implemented immediately. These energy efficiency measures can be undertaken at low cost, paying back initial investment in a matter of months or a few years, and, they would provide long-term cost savings.

The report also points out, that using energy more efficiently does not necessarily mean seeing a decreased level of service. With advances in technology and simple changes in behavior, significant savings can be realized without compromising level of service.

The authors evaluated possible policy recommendations based on:

- Return On Investment (ROI)
- Benefit/Cost Analysis (B/C)
- Carbon Reduction
- Present Value of Savings (PVS)
- Ease of Implementation

These recommendations are broken out into nine categories:

1. State Leadership
2. Funding Energy Efficiency Programs
3. Public Education and Outreach
4. Collect Baseline Data
5. Existing Residential Buildings
6. New Residential Construction
7. Existing Commercial Buildings
8. New Commercial Construction
9. Public Buildings

The report also provides a preliminary budget for costs of implementing and maintaining recommended energy efficiency programs and policies.

Other Organizations

The Cold Climate Housing Research Center tests new building technologies in Alaska.

The Alaska Craftsman Home Program, Inc. educates Alaskans in energy-efficient building technology specifically for northern regions and their diverse climatic zones.

The Alaska Building Science Network promotes energy efficiency as an essential component of durable, safe, and affordable housing in Alaska.

Cooperative Extension Service of the University of Alaska Fairbanks operates the Energy and Housing Program. This program focuses on providing the best possible housing technology information to Alaskan home owners and builders.

There are five weatherization assistance program providers in Alaska and fifteen regional housing authorities. Each provider is responsible for a specific Alaskan region. The program providers are:

RurAL CAP
Tanana Chiefs Conference
Interior Weatherization, Inc.
Alaska Community Development Corp.
Municipality of Anchorage

Conclusions and Recommendations

The future of Alaska demands that every resident get the most energy out of each unit purchased. Energy efficiency has the highest return on investment of any energy source. The environmental implications are extremely high as well. Many facility owners and operators tend not to think about their usage, yet it is the easiest and fastest way to keep costs down. End-use efficiency can keep energy prices stable while reducing the need for new supply-side infrastructure, or providing the extra time to build that infrastructure. Careful project design can mitigate comfort issues that may arise from new lighting systems and different building controls.

The technology is mature, but constantly evolving. Owners and operators must keep current on the changes. Before implementing changes they must assure proper testing has been completed. Conservation has a strong future in slowing the advancement of global warming by reducing or displacing production of greenhouse gases from the electricity sector.

Efficiency and conservation easily become a way of living. Constant education and outreach will be required to reinforce good habits. Safe removal and disposal (recycling) of old equipment should be ongoing. Much like the Federal Government does through mandatory reductions and use of alternatives, the State of Alaska should lead all of Alaska by example.

Beaver Washeteria - Public buildings such as washeterias afford opportunties for energy projects, particularly space heating from biomass or waste heat recovery from diesel engines. The community of Tanana, for example, installed two cordwood boilers in 2007 to heat their washeteria.

HYDROELECTRIC POWER GENERATION

AEA Program Manager: Douglas Ott (771-3067)

TECHNOLOGY SNAPSHOT: HYDROELECTRIC	
Installed Capacity (Worldwide)	654,000 MW
Installed Capacity (Alaska)	Approximately 423 MW
Resource Distribution	Resource potential exists throughout many areas of the state, with most developed projects in the southeast and southcentral portions of the state; Alaska has 40% of U.S. untapped hydropower (192 billion Kwh energy potential)
Number of communities/ population impacted	100+ (potentially +80% of Alaska's population)
Technology Readiness	Commercial (mature)
Environmental Impact	Requires proper design to mitigate impacts to downstream aquatic life, downstream water quality, and recreational uses
Economic Status	Unit costs are variable and site specific. Where found to be economic, hydroelectric installations provide reliable, inexpensive renewable energy

Alaska has enjoyed a long and rich history with hydroelectric power. By 1908, southeast Alaska alone had over 30 developed water power sites with a capacity of 11,500 kW. The vast majority, built by private developers, provided power for industrial operations, mainly for the gold mining works in Juneau and on Douglas Island. Today hydropower in Alaska provides 24%[1] of the statewide electrical power. Major developers include the State of Alaska and public and privately owned utilities. These power plants have proven to be long-term, reliable, and relatively inexpensive sources of power. Hydropower installations have the reputation for being robust and durable, operating successfully at some sites for more than a century. Hydropower's low operation and maintenance costs coupled with long lifetimes result in stable power rates. In Alaska, hydropower is currently the largest and most important producer of electricity from a renewable energy source. With increased interest in replacing fossil-fuel-powered generation with renewable energy resources, the statewide inventory of installed hydropower capacity will continue to expand.

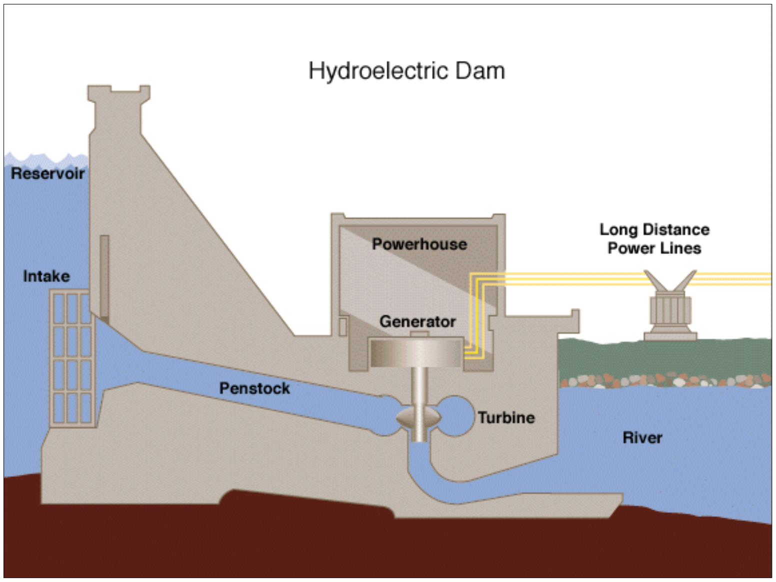


Figure 1.
Typical High-Wall Reservoir Hydroelectric Dam Structure.

Source: Army Corp of Engineers

Hydroelectric power is the generation of electric power from the movement of water flowing from a higher to a lower elevation. In contrast, hydrokinetic technology (covered in a separate technology chapter in this report) is a pre-commercial technology that uses river current to generate electric power. A hydroelectric facility requires a dependable flow of water and a reasonable height of fall of water, called the head. In a typical installation, water is fed from a reservoir through a conduit called a penstock into a hydraulic turbine. The pressure of the flowing water on the turbine blades causes the shaft to rotate. The rotating shaft is connected to an electrical generator, which converts the shaft motion into electrical energy. After exiting the turbine, water is discharged to the river in a tailrace.

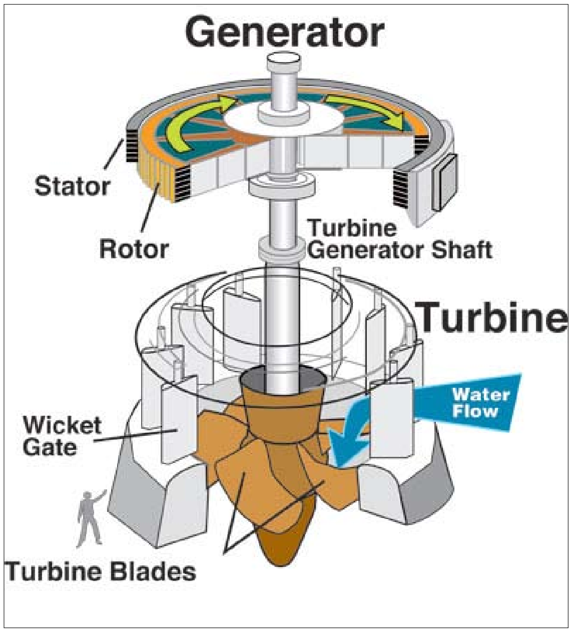


Figure 2.
Cross section of hydraulic turbine generator.

Source: Army Corp of Engineers

Before a hydroelectric power site is developed, engineers must assess how much power will be produced when the facility is complete. They also review the natural conditions that exist at each site: surface topography, geology, river flow, water quality, and annual rainfall and snowfall cycles. Extensive studies are conducted to evaluate the site's environmental conditions, land status and other factors that may influence the configuration of the hydro plant and the equipment selection.

A given amount of water falling a given distance will produce a certain amount of energy. The head and the discharge at the power site and the desired rotational speed of the generator determine the type of turbine to be used. The greater the head, the greater the potential energy to drive turbines. More head or faster flowing water means more power.[2]

The steep mountains, abundant rain and snow, and relatively mild winter temperatures in Southeast and Southcentral Alaska provide the ideal hydrologic conditions for hydroelectric power.

South Fork Drainage, Prince of Wales Island, Southeast Alaska.

Source: Alaska Energy Authority, 2008.

To find the theoretical horsepower (the measure of mechanical energy) from a specific site, this formula is used:

$$THP = (Q \times H)/11.81$$

where: THP = theoretical horsepower

Q = flow rate in cubic feet per second (cfs)

H = head in feet

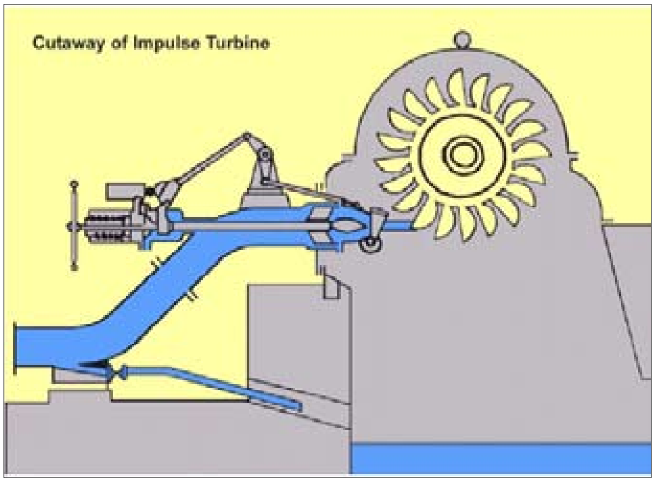
11.81 = a constant

A more complicated formula is used to refine the calculations of this available power. It takes into account losses in the amount of head due to friction in the penstock and variations due to efficiency levels of mechanical devices used to harness the power. To determine how much electrical power can be produced, the mechanical measure (horsepower) must be converted into electrical terms (Watts). One horsepower is equal to 746 watts (U.S. measure).

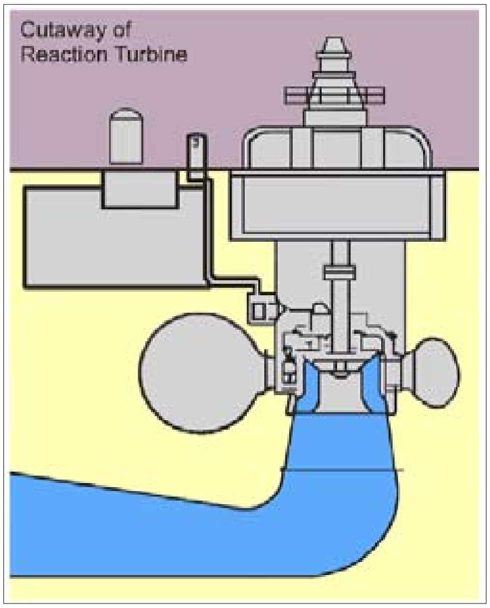
Impulse and reaction turbines are the two most commonly used types. Other types of turbines include fixed pitch propeller and crossflow (also called the Ossberger or Banki turbines). Each has a specific operating range in terms of hydraulic head and power output. In order to optimize the power output and reduce capital costs, the specific turbine to be used in a power plant is not selected until all operational studies and cost estimates are complete. The turbine selected depends largely on site conditions.

A reaction turbine is a horizontal or vertical wheel that operates with the wheel completely submerged, a feature that reduces turbulence. In theory, the reaction turbine works like a rotating lawn sprinkler, where water at a central point is under pressure and escapes from the ends of the blades causing rotation. Francis or Kaplan turbines are reaction machines that utilize both hydraulic pressure and kinetic energy to create rotating shaft work. Reaction turbines are the type most widely used in Alaska.

An impulse or Pelton-type turbine is a horizontal or vertical wheel that converts the fluid's change in potential energy (hydraulic head) into kinetic energy by water striking its buckets or blades to make the extractable rotating shaft work. Pelton or Turgo impulse turbines may have single or multiple nozzles that accelerate flow to produce high velocity jets that impinge on a set of rotating turbine buckets to transfer their kinetic energy. The wheel is covered by a housing, and the buckets or blades are shaped so they turn the flow of water about 170 degrees inside the housing. In contrast to a reaction turbine, the fluid contained in the impulse turbine does not completely fill all available void space, and the turbine operates at ambient pressure. After turning the blades or buckets, the water falls to the bottom of the wheel housing and flows out.



Source: Bureau of Reclamation, 2005.



Source: Bureau of Reclamation, 2005.

Low-Head Hydropower

A low-head dam is one with a water drop of less than 65 feet and a generating capacity less than 15,000 kW. Large, high-head dams can produce more power at lower cost than low-head dams, but construction of large dams may be limited by lack of suitable sites, by environmental considerations, or by economic conditions. The key to the usefulness of low-head units is their lower capital costs and the ability to satisfy local power needs with the available resource.

Run-of-the-River

Run-of-the-river hydro facilities use the natural flow and elevation drop of a river to generate electricity. Facilities of this type are optimally built on rivers with a consistent and steady flow.

Power stations on rivers with great seasonal fluctuations require a large reservoir in order to operate during the dry season. In contrast, run-of-the-river projects do not require a large impoundment of water. Instead, some of the water is diverted from a river and sent into a pipe called a penstock. The penstock feeds the water downhill to the power station's turbines. Because of the difference in elevation, potential energy from the water upriver is transformed into kinetic energy and then to electrical energy. The water leaves the generating station and is returned to the river with minimal alteration of the existing flow or water levels. With proper design, natural habitats are preserved, reducing the environmental impact.

Run-of-the-river power plants typically have a weir or diversion structure across the width of the river. This weir contains an intake structure, often consisting of a trash rack, an intake screen, and de-sanding elements to conduct the water into the penstock. These installations have a small reservoir behind the diversion to keep the intake flooded and reduce icing problems.

The output of the power plant is highly dependent on the drainage basin hydrology. Spring breakup will create a lot of energy, while flow diminishment during winter and dry seasons will create relatively little energy. A run-of-the-river power plant has little or no capacity for energy storage, and so cannot coordinate the output of electricity generation to match consumer demand. Most run-of-the-river applications are small hydro.

Small, Mini, and Micro Hydropower

Small hydro is the development of hydroelectric power on a scale that serves a community or an industrial plant. The definition of a small hydro project varies, but a generating capacity of up to 10 MW is generally accepted as the upper limit of what is termed small hydro. Small hydro can be further subdivided into mini hydro, usually defined as less than 1,000 kW, and micro hydro, which is less than 100 kW. Micro hydro applications might serve for single families or small enterprises, while mini hydros might be appropriate for small communities.

A small hydro plant might be connected to a conventional electrical distribution network as a supplemental source of renewable energy. Alternatively, a small hydro project might be built in an isolated area that would be uneconomic to serve from a network, or in areas where there is no electrical distribution network. Small hydro projects usually have minimal reservoirs and civil construction work, consequently a relatively low environmental impact.

A large and growing number of companies offer standardized turbine generator packages in the approximate size range of 200 kW to 10 MW. These water-to-wire packages simplify the planning and development of the site, since one vendor looks after most of the equipment supply.

Non-recurring engineering costs are minimized, and development cost is spread over multiple units, so the cost of such systems is improved. While synchronous generators capable of isolated plant operation are often used, small hydro plants connected to an electrical grid system can use economical induction generators to further reduce installation cost and to simplify control and operation.

Micro hydro plants may use purpose-designed turbines or industrial centrifugal pumps connected in reverse to act as turbines. While these machines rarely have optimum hydraulic characteristics when operated as turbines, their low purchase cost makes them attractive for micro hydro class installations.

Regulation of small hydro generating units may require water to be spilled at the diversion to maintain the downstream stream habitat. Spilling will also happen when the natural flow exceeds the hydroelectric system capacity, since the project will generally have no reservoir to store unused water. For micro hydro schemes feeding only a few loads, a resistor bank may be used to dissipate excess electrical energy as heat during periods of low demand. In a sense this energy is wasted, but the incremental fuel cost is negligible so economic loss is minor.

Since small hydro projects may have minimal environmental and licensing procedures, the equipment is usually in serial production. Civil works construction is also limited. The small size of equipment also makes it easier to transport to remote areas. Fore these reasons, small hydro projects may reduce development time.

Small hydro and mini hydro can be used as alternative energy sources in off-grid communities with small loads. Small hydro tends to depend on small water turbines fed directly by rivers and streams. When compared with other renewable energy alternatives like wind and solar, run-of-the-river hydroelectric generators are able to deliver a relatively consistent electric supply throughout the day.

Run-of-the-river hydroelectric generators in Alaska do not provide the same seasonally consistent electric supply that larger hydroelectric projects do. This is a result of the seasonal changes in the flows of Alaska rivers, with diminished flow rates during the winter months. The dams and reservoirs of larger hydroelectric projects provide for energy storage, holding water to be used to generate electricity when flows are lower. Unfortunately, most Alaska electric loads are highest during the winter, the same time that river flow (and the electric power generation capability of small and run-of-the-river hydro) is at its lowest. This lowers the amount of run-of-the-river hydro capacity that can be installed without significant amounts of excess capacity in the summer.

Conventional Hydroelectric Storage Projects

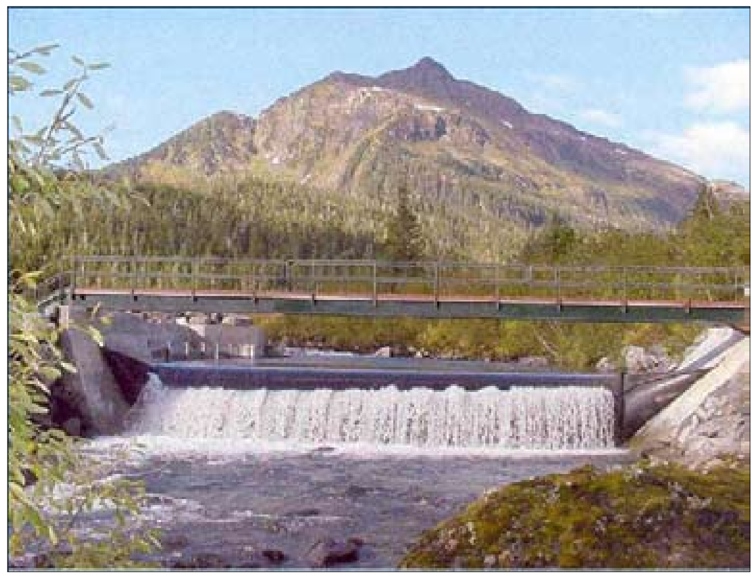
When suitable hydraulic heads are not present or when power needs are substantial, dams are constructed across rivers to store water and create hydraulic head to drive the turbomachinery. Dams typically last for 50 to 100 years and so, are constructed of durable materials like reinforced concrete, roller-compacted concrete, earth, and crushed rock. Smaller dams may be constructed of steel or timber crib design. They vary substantially in terms of height and storage volume, depending upon local topography. There are several design approaches used for concrete dams, including solid and hollow, gravity and arch geometries.

In addition to the actual dam structure, there are a number of other major design considerations. For example, the penstock inlet manifold (usually with screens to keep debris and fish from entering the turbine) and the discharge or tailrace system must be designed to maintain the hydraulic head and minimize the effects of sedimentation, silt, and ice build-up. Substantial effort goes into the design of the dam spillway to safely direct extreme flows downstream of the dam when the available reservoir storage is inadequate to contain it.

Where the topography allows, several successful design concepts are available to help mitigate the environmental impacts of conventional storage hydropower projects. In regions with high-elevation natural lakes, lake taps may be utilized to feed a power tunnel bored in rock to carry water to the downstream powerhouse. This approach reduces the need to construct a dam; the tunnel serves in place of the penstock; and the lake is utilized as a natural storage reservoir. At other sites, natural barrier waterfalls can facilitate licensing of upstream hydro development through their function as fish migration barriers. Fish protection and passage facilities and eco-friendly turbines can also be designed to mitigate fisheries impacts of hydroelectric facility construction. In order to be constructible, all hydro projects must pass rigorous assessment. Environmental effects must be determined. Mitigation measures, compliance monitoring, and environmental follow-up programs must be established.

A strong attribute of conventional hydropower is the dispatchability that results from the ability to control the rate of power production through storage and release of water contained behind the dam. Given the general increase in electrification that is occurring worldwide, the demand for using hydropower reservoirs for both base-load and peaking applications is rising. Other factors may also lead to increased interest in conventional hydropower. The variable nature of other renewable energy sources like wind and solar makes pairing with hydro energy storage an attractive option for integrated supply systems.

Additionally, the scale of energy production attainable with hydroelectric storage lends it to connection with large electrical grids to displace conventional fossil fuel-based power sources with clean, non-carbon-based power. Fuel switching to inexpensive hydropower may be possible in some situations for home heating and (someday) for plug-in hybrid cars.



Power Creek Hydro project

The Alaska Division of Energy published the Rural Hydroelectric Assessment and Development Study in 1997. The study developed a database of existing and potential hydroelectric projects in Alaska. At that time, a total of 1,144 potential hydroelectric sites were screened, resulting in two potential projects with positive net benefits. These two projects, and another two that were close to potential positive net benefits were subjected to additional engineering review.

In 2007 Crimp, Colt, and Foster updated the capital cost estimates in the hydroelectric project database to year 2005 dollars.[3] The estimated capital cost per installed kW in 2005 dollars ranged from $1,500 to $250,000 (mean = $25,800). Annual operation and maintenance (O&M) costs for each hydro project were also estimated for the project's screening process in the earlier study, generally equal to 3% of capital cost. Project viability was re-screened under pessimistic, mid-case, and optimistic scenarios.

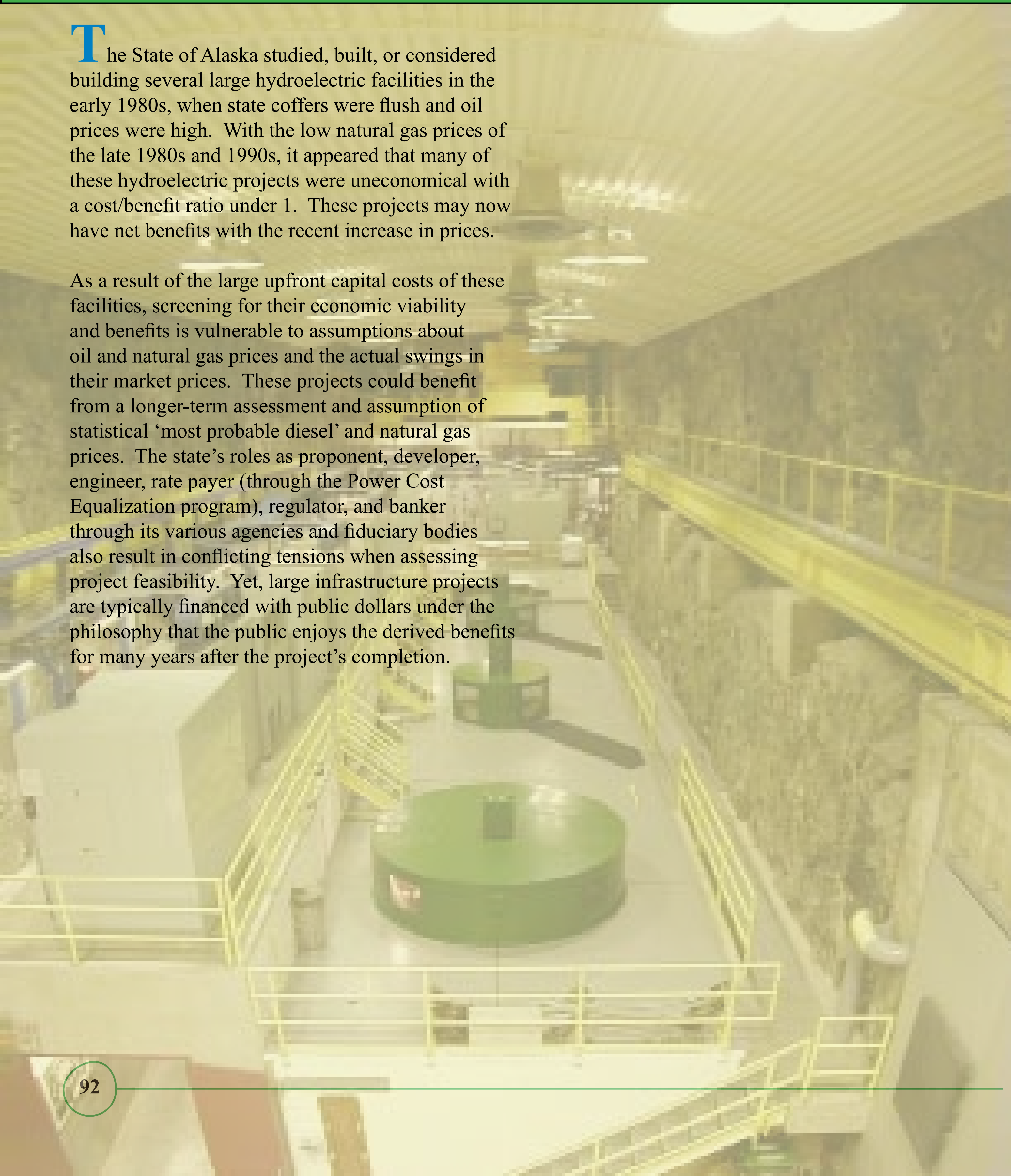
The high capital cost of hydro (both absolute and especially on a per kW basis for smaller projects) is the chief impediment to its economic feasibility. This cost tends to decrease over time as the original capital costs are paid down from power sales revenue and the low O&M cost features of hydropower prevail, however, higher fuel prices in the 2007 analysis, relative to those considered in 1996, were sufficient to propel several projects into the ranks of potentially feasible projects.

As part of the state energy plan process, a new screening of available hydro site studies and investigations was conducted by AEA. Utilizing a team of hydropower experts (the Hydro Technology Working Group) as a sounding board, this team took a fresh look at potential hydro sites closest to existing communities and used a variety of high level screens to identify the sites most viable for further investigation. See the Hydro Technology Working Group Recommendations found later in this narrative). The data identified from this process have been incorporated into the energy plan's master database of energy technologies. Though not all sites are economic at today's fuel prices, some 99 sites have been identified in this screening as having potential for future hydro development. Further information on these sites is available upon request.

CASE STUDIES

The State of Alaska studied, built, or considered building several large hydroelectric facilities in the early 1980s, when state coffers were flush and oil prices were high. With the low natural gas prices of the late 1980s and 1990s, it appeared that many of these hydroelectric projects were uneconomical with a cost/benefit ratio under 1. These projects may now have net benefits with the recent increase in prices.

As a result of the large upfront capital costs of these facilities, screening for their economic viability and benefits is vulnerable to assumptions about oil and natural gas prices and the actual swings in their market prices. These projects could benefit from a longer-term assessment and assumption of statistical ‘most probable diesel’ and natural gas prices. The state’s roles as proponent, developer, engineer, rate payer (through the Power Cost Equalization program), regulator, and banker through its various agencies and fiduciary bodies also result in conflicting tensions when assessing project feasibility. Yet, large infrastructure projects are typically financed with public dollars under the philosophy that the public enjoys the derived benefits for many years after the project’s completion.



Case Study: Four Dam Pool

The Four Dam Pool projects are four hydroelectric facilities (dams and lake tap projects) built by the State of Alaska in the early 1980s in Kodiak, Valdez/Glennallen, Ketchikan, and Wrangell/Petersburg. The State paid for a portion of the dams, and it provided loans through the Power Development Revolving Loan Fund for the remainder of the cost. The total cost for the project in 2007 dollars is estimated at $811 million: $493 million in state funding, and $318 million in grants and loans.[4]

Facility Name	Communities Served
Swan Lake	Ketchikan
Tyee	Wrangell and Petersburg
Terror Lake	Kodiak
Solomon Gulch	Valdez and Glennallen

The projects were originally owned by the State of Alaska, Alaska Power Authority, with electricity sold to local utilities through Power Sales Agreements. In January 2002, AIDEA loaned up to $82 million to the utilities to acquire the dams from AEA: $77 million for the dams and up to $5 million to construct an intertie between the Swan Lake hydroelectric project and the Lake Tyee hydroelectric project to move surplus energy from Wrangell/Petersburg to Ketchikan.[5] The Swan-Tyee Intertie is expected to cost over $100 million when construction is completed in 2009. The Alaska legislature provided for non-payment or forgiveness of a non-current loan owed to the AEA upon closing of the bond sale; this was the outstanding balance of the original loans.[6]

Case Study: Bradley Lake Hydroelectric Project

The Bradley Lake hydroelectric project was constructed by the Alaska Power Authority on the Kenai Peninsula near Homer, Alaska. The Alaska legislature appropriated $168 million for what was estimated to be a $245 million project. The project, which cost over $300 million (including reserve fund balances, of $479 million 2007 dollars), went into commercial operation in 1991. The project includes a concrete-faced and rock-filled gravity dam, 610 foot long, 125 foot high, and a 3.5-mile power tunnel and steel-lined penstock. The project transmits power to the state's main grid via two parallel 20-mile transmission lines. Homer Electric Association under contract with AEA now operates the project. Bradley Lake serves Alaska's Railbelt from Homer to Fairbanks as well as the Delta Junction area.[7]

The power from Bradley Lake is shared among the Railbelt utilities via the intertie, according to a formal sharing agreement.

Utility Share of Bradley Lake	Share
Chugach Electric Association	**30.4%**
Anchorage Municipal Light and Power	**25.9%**
Homer Electric Association	**12.0%**
Matanuska Electric Association	**13.8%**
Seward Electric Utility	**01.0%**
Golden Valley Electric Association	**16.9%**

Also in Southcentral Alaska, the Eklutna hydroelectric facility was brought on line in 1955 by the federal government. In 1994 it was taken over by Anchorage Municipal Light & Power. As the cheapest energy source connected to the Railbelt energy grid, it currently produces power at a rate of a few cents per kWh.

The Cooper Lake hydroelectric facility is owned and operated by Chugach Electric Association. It began operation in 1960 and was recently relicensed by the Federal Energy Regulatory Commission.

A number of smaller hydroelectric projects owned by individual utilities are located across the state, mostly in Southeast Alaska. There are also some very small private facilities, most of which are owned by fish processors.

A list of the larger facilities serving utilities follows:

Facility	Installed Capacity (MW)
Annex Creek	**3.6**
Beaver Falls	**5.4**
Black Bear Lake	**4.5**
Blind Slough	**2**
Blue Lake	**6**
Bradley Lake	**126**
Chester Lake	**1**
Cooper Lake	**16.7**
Dewey Lakes	**0.9**
Eklutna	**30**
Falls Creek	**0.8**
Goat Lake	**4**
Gold Creek	**1.6**
Green Lake	**18.6**
Humpback Creek	**1.3**
Kasidaya Creek	**3**
Ketchikan	**4.2**
King Cove	**0.85**
Lake Dorothy	**14.3**
Larsen Bay	**0.4**
Pelican	**0.7**
Petersburg	**2**
Power Creek	**6**
Purple Lake	**3.9**
Salmon Creek	**6.7**
Silvis	**2.1**
Skagway	**1**
Snettisham	**78**
Solomon Gulch	**12**
South Fork Black Bear	**2**
Swan Lake	**22.4**
Tazimina	**0.8**
Terror Lake	**20**
Tyee	**20**
Total	**423.35 MW**

Case Study: Southeast Alaska

Hydroelectric generating facilities and diesel generators provide a significant portion of the electric power generation in Southeast Alaska. The state and the federal government, as well as certain communities and utilities have developed existing hydroelectric generating plants in Southeast Alaska. Hydroelectric facilities provide the majority of the power requirement in Juneau, Ketchikan, Sitka, Petersburg, Wrangell, Skagway, Haines, Metlakatla, Craig, and Klawock.[8] The largest in Southeast Alaska is the Snettisham hydroelectric facility, providing 80% of the power used by Juneau and Douglas. Built by the USCOE in the 1979s, and sold to the State of Alaska in 1998, Snettisham is operated by Alaska Electric Light and Power under contract with AIDEA.

In some communities the hydroelectric facilities are capable of providing electricity in excess of the community load. In response, electric customers in these communities are replacing or supplementing diesel space and water heating systems with electric once. If enough customers convert to electric heating, the surplus electric capacity will dissipate and diesel generators will be needed to meet the load requirements. One method of addressing this issue is interruptible electric space and water heating when reservoir levels are low or electric use is high during the winter. During low water years in Sitka, the utility has had to ask people to heat with wood or diesel[9] while it interrupts electric service to electric heaters.[10] Transmission line damage from avalanches disrupted the flow of hydroelectric power from the Snettisham hydro project to Juneau for six weeks in 2008. During this period, power was restored using back-up diesel generation at roughly 5x the power sales rate of Snettisham hydropower.

Snettisham Hydroelectric facility. Above: Long Lake; Below: Outside view of the Snettisham Hydroelectric facility.

Case Study: South Fork Prince of Wales Island

Many communities on Prince of Wales Island are electrically intertied and are supplied power primarily from the Black Bear Lake hydro project (BBL).[11] However, over the last 10 years system load growth fully utilized the capacity and energy available from BBL. Supplemental diesel-powered generation was required to meet this increased demand. To minimize dependency on high-cost diesel-generated energy, Alaska Power & Telephone Company began investigating renewable resource energy sources on the island. Research led to the selection of South Fork enhanced by its close proximity to existing roads and power and communication lines servicing BBL,as the most feasible project.

South Fork Impoundment.

With grant/loan assistance from the Denali Commission and the Alaska Energy Authority, construction of this 2 MW run-of-the-river hydroelectric project began in the spring of 2004 and came on line December 2005. AP&T was the general contractor of the project, securing necessary permits, providing engineering design, and constructing the project with their own work force and seasonal labor.

The South Fork hydroelectric facility has already accumulated over 1,000 hours of operation, supplementing the BBL facility. The power plant controls were incorporated into the BBL SCADA system, enabling plant operators to remotely monitor and control the new facility. While South Fork has limited storage capacity, it will significantly reduce the energy requirement from BBL, enabling BBL to maintain water in storage for low rainfall periods. This will significantly reduce the area's dependence on diesel-generated energy.

Three hydropower projects are now under construction in Alaska. Falls Creek near Gustavus is being built by Gustavus Electric Company, Kasidaya Creek, between Haines and Skagway, by Alaska Power and Telephone Company, and Lake Dorothy by Alaska Electric Light and Power.[12] FERC licenses have also been issued for hydropower projects at Reynolds Creek and Mahoney Lake, and soon to be issued for Whitman Lake.

Recent Grant Applications

AEA sought interest in study and development of alternative and renewable energy projects through three different grant application cycles in 2008. Applications for hydropower project development and construction have been received for 64 projects. Requested grant funds total $159.8 million for facilities costing $3.35 billion in capital costs. Because the applications are currently under review and funds requested exceed grant funds available, not all applications will receive the amount requested. However, this information is an indication of the current level of interest in hydro development in Alaska.

Chakachamna Hydroelectric Project

The Chakachamna hydroelectric project is currently under study by TDX Power. Located on the western side of Cook Inlet, the project would entail a lake tap, 12-mile power tunnel, and a 40-mile transmission line extension to provide 330 MW of energy to the Railbelt grid at 1600 MWh annually. Originally studied by the Alaska Power Authority in the 1980s, the project as currently envisioned would divert water from the Chakachatna River to the McArthur Drainage Basin.

Susitna Hydroelectric Project

The hydroelectric potential of the Susitna River has been studied over many decades.[13] The initial studies were done by the Bureau of Reclamation in the early 1950s; in the 1970s , studies by the Corp of Engineers reconfirmed the feasibility of Susitna River hydropower development. In 1980 the Alaska Power Authority (now Alaska Energy Authority) was commissioned a review of studies to date and a comprehensive feasibility study to determine whether hydropower development on the Susitna River was a viable option.[14] Based on these and other studies and the urging of the Alaska Legislature, the AEA submitted a FERC license application in 1983. The license application was amended in 1985 for the construction of a two-dam, three phase construction project. The estimated cost of that project was $5.9 billion.

Arriving at a plan for bond financing was found to be difficult for a project of this scale, one which was to be constructed in phases over a 20-year time period. Cash payment of a portion of the construction costs was proposed as a means of reducing power costs to customers.[15]

As a result of the high cost of the project, the relatively low cost of gas-fired electrical generation in the Railbelt, and the effect on the state budget of the declining price of oil in the early 1980s, the project was terminated by the Board of Directors of the Power Authority in March 1986. At that point, approximately $227 million had been appropriated to the project from FY79-FY86 ($382 million 2007 dollars) and $145 million had been spent. Extensive field work, biological studies, and activities to support the FERC license application were conducted with these funds. Though the conclusion reached in 1986 was that the impacts of the project were manageable, the license application was withdrawn. The project data and reports were archived to be available for reconsideration sometime in the future.

More recently the Alaska Energy Authority was authorized $2.5 million in funding to perform a Susitna Hydro Feasibility Study and Cost Estimate as part of the FY 2009 Alaska capital budget. Two distinct tasks were identified in the legislation. First, the 1984 cost estimate for construction of the Susitna hydro project using current construction and design technology will be reviewed and updated ($1.5

million). This renewed analysis will produce four alternatives of development for the project, with energy output and costs.

Second, a Railbelt wide integrated resource and transmission study will consider the four incremental Susitna development alternatives, in conjunction with other Railbelt wide generation projects (1.0 million). The analysis will make use, to the maximum extent possible, of the phased project development considered in 1984, but key to the analysis will be new assessment of long-term Railbelt load growth, and matching the project the realistic future Railbelt needs.

This integrated resource plan will yield an economic plan for construction of power generators, transmission lines, and fuel aggregation infrastructure to meet the capacity, energy and reliability needs of the Railbelt over the next 50 years. The plan will include creation of a diversified power portfolio, and robust transmission system by year 10 that can supply reliable postage stamp rate power for all Railbelt utilities. The Susitna project will be a key economic element in the creation of this plan.

According to a November 2008 presentation to the Alaska Energy Authority, the two dam configuration of the Susitna hydro project would be capable of producing approximately 7 million MWh annually.[16]

Hydro Technology Work Group Recommendations

The hydro technology work group met several times during the summer and fall of 2008. The work group membership consisted of consulting engineers, resource managers, interested citizens, and AEA personnel. Assistance was provided in selecting the steps in the hydro resource screening and evaluation. The working group provided peer review and validation of preliminary screening results. Specific recommendations of the group included the following:

- Hydro projects do not lend themselves to utilization of unit cost factors in preparing estimates of capital cost; rather, site-specific analysis is required to arrive at optimal hydro development schemes and their associated capital costs.
- Where excess hydropower is available, fuel switching to electric home heating is likely to occur in communities with low-cost hydropower. This impact will substantially increase the power sales.
- The work group recommended a 50-year working life be used in economic evaluation of hydro facilities.
- Pumped storage hydro projects are not viable in Alaska at present, since the power rate structure currently used by utilities here offers no rate differential for peak versus off-peak generation; if possible this could be feasible for energy storage, should large wind farm generation be brought online in the future.
- Research is needed to discover ways to reduce intake icing conditions and integrate schemes for small hydro in village settings. Needed also are standardize plans for propeller and crossflow turbine runners (to reduce manufacturing costs and promote use of materials such as composite blades and others not requiring extensive metal casting), to utilize heat recovery for heat load dumps used for hydro energy frequency regulation. Tests on coanada intake screens for cold weather hydro applications are needed, as are water conservation schemes for preservation of reservoir storage during frequency regulation. Standardized plans for small hydro applications such as intakes, powerhouse, induction plants, and tailraces are needing research. Alaska-friendly fish passage designs for in and out of a lake/reservoir, how best ways to provide for flushing flows and sediments to replenish spawning gravels in fish streams, optimal winter instream flow releases for traditional hydropower projects, and improved methods to predict snow melt and runoff for modeling reservoir operations
- The group recommended that prior hydro studies be made available online to promote future development opportunities.
- The group recommended working toward the establishment of a fair, efficient, and timely authorization permitting process for new hydropower projects, particularly for run-of the-river hydros.

Conclusions

The future looks bright for hydropower development in Alaska. Hydroelectric projects produce power that is reliable, renewable and non-polluting. Though they can be expensive to license and construct, hydroelectric facilities produce long-term dividends of power sales at some of the lowest cost rates available today. Hydropower rates are not subject to the price swings and escalation that fossil fuels experience. Careful project design can mitigate environmental impacts that are resolved during the licensing stage in collaboration with resource agency consultation.

Hydropower technology is mature and not subject to performance risks inherent with some of the new energy technologies that have yet to reach commercial-stage development. Alaska has abundant hydroelectric potential, especially in the Southcentral and Southeast portions of the state; other potential sites are available in the Aleutians, Southwest, and the Interior. Transmission of power from large hydro sites can be accomplished through grid interties to neighboring communities, thus displacing fossil fuel generation. Hydropower integrates well with wind power in community power systems. It has a strong future in retarding the advancement of global warming by reducing or displacing production of greenhouse gases from the electricity sector. The domestic energy security available from utilizing hydropower is unsurpassed and promotes the goal of energy independence.

In its latest World Energy Outlook published in November 2008, the International Energy Agency has requested decisive action to secure supplies of affordable, reliable energy and create an environmentally benign energy system. The development of hydroelectric facilities is a positive response to that call for action.

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Wind Energy Technologies

AEA Program Manager: Martina Dabo (771-3027)

Wind Turbine at Selawik

TECHNOLOGY SNAPSHOT: Wind	
Installed Capacity (Worldwide)	Over 100,000 MW worldwide
Installed Capacity (Alaska)	4,505 kW installed; 4,415 kW under construction
Resource Distribution	Potentially available to communities in all regions of Alaska although generally focused in coastal areas and throughout low-lying delta plains.
Number of communities impacted	At least 134 rural communities have viable wind resource. Additional communities along the Railbelt have yet to be assessed.
Technology Readiness	Wind-diesel systems are commercial to early-commercial depending on level of wind penetration to existing load. Larger turbines appropriate for the Railbelt are fully commercial.
Environmental Impact	Impacts on local and migratory bird populations although little impact currently documented. Potential for noise and visual impacts when sited close to a community. Most impacts can be minimized by appropriate siting, design, and operation.
Economic Status	Wide disparity on payback. For rural areas payback is highly dependent on associated balance of system costs and price of offset diesel fuel.

Introduction

Wind is caused by temperature and pressure fluctuations in the atmosphere as the sun warms the earth. Wind devices are powered by air. Air moving relative to an object such as the blades of a wind turbine (or the winds of a plane) imparts a force on that object.

Wind turbines use this aerodynamic force to convert the kinetic energy of the wind into mechanical energy that can be harnessed for use. The energy in the wind can be defined for a specific unit of area that the wind is flowing through in a unit of time. Wind energy is directly related to the area swept by the turbine blades, air density, and the cube of wind speed. A doubling of the wind speed increases the power from the wind by eight times. For this reason, the most important factor in calculating wind power is determining wind speed. This fact is important when considering the integration of wind into existing power systems. In most instances we need our power to be constant, and wind energy is as variable as the blowing wind.

A wind turbine generator (WTG) uses a wind turbine rotor, with turbine blades to transform wind energy into mechanical energy; and a generator, to transforms that mechanical energy into electrical energy. Many different types of wind turbines are available. Sizes vary. Small (10 kW or less) wind turbines which are typically used for individual homes or small businesses. Medium-sized (50kW - 1000kW) ones are used for remote communities and other grid-connected, distributed generation. Large turbines (1MW or more) are generally used in large wind farms.

This section focuses on medium and large wind turbines. without addressing the application of small wind turbines. More information on small wind turbine applications can be found on the Wind Powering America, small wind website at http://www.windpoweringamerica.gov/small_wind.asp, or the Alaska Energy Authority website at http://www.akenergyauthority.org/programwindenergybasics.html. Various publications like Wind Power: Renewable Energy for Home, Farm, and Business, by Paul Gipe (2004), might also be helpful.

In rural communities now using diesel generators, it is important to understand that wind energy alone cannot replace diesel generation. In most applications, when the wind is blowing, wind energy is used to reduce dependence on and consumption of diesel fuel. Diesel power is relied on when available wind energy is insufficient. These wind-diesel power systems are described in greater detail in the next section.

Alaska has significant potential for wind technology development throughout the state, but the best resources are concentrated near the coast and on the large coastal plains and river deltas, like the Yukon-Kuskokwim region. Communities in interior Alaska may also have wind resources, but they are generally confined to passes, hills, or ridge tops. In nearly all cases, specific assessments will likely be required.

Obvious opportunities exist, but there are environmental and technical challenges related to the deployment of wind devices in Alaska. Some of these challenges are common to installations in any location, while others are more specific to Alaska. Most environmental concerns relate to potential impacts on birds. Often, coastal regions with good wind resources also have strong bird populations, including the King Eider, Black Scoter, and the Steller’s Eider, which is an endangered species. Two general laws govern turbine impacts on birds, the Endangered Species Act and the Migratory Bird Treaty Act. At this point there is a limited amount data on the impacts of Alaska’s current wind projects on local species and population.
Survivability and performance of turbines in the

Arctic is another consideration. Wind turbine performance in Alaska has been good, however there is relatively limited information due to the small number of installed wind systems. Additionally there is little in-state maintenance support for most wind turbines at this time, however, with the continued growth of wind power in Alaska, this expertise is being developed. Some areas of Alaska are also subject to substantial amounts of rime icing and extremely low temperatures, these conditions may have a significant impact on wind turbine performance and reliability.

Challenges still exist with the integration of wind technologies into new or existing diesel power plants. Combined systems can be complex, and care must be taken during the development of the project to insure that the resulting system will perform satisfactorily. Also, the operational complexity of the system changes as the amount of wind energy increases as compared to the load.

Although a wind map has been completed for the state, additional local wind assessments are required to justify project development on any meaningful scale. The installation of an anemometer and collection of enough data to understand the local wind resource can take over a year.

By the end of 2008, nine remote communities will have wind turbines installed. An additional six projects will be under construction. There is a single 100 kW wind turbine installed on the Railbelt near Delta Junction. Studies are being undertaken to assess other, much larger projects from Homer to Fairbanks.

There are many different wind turbine designs, but all of them have things in common. The main component that transforms the wind energy into mechanical energy is the rotor, which includes the blades. Based on this commonality, wind turbines are classified by the structure of the rotor and its location in the airflow. The two main types of wind turbine are horizontal axis and vertical axis, referring to the axis of the blade rotation. At this time, the only type of configuration commercially available for medium and large installations is the horizontal axis turbine, so it is the only one considered here.

The rotor of a horizontal axis wind turbine rotates around a horizontal axis, parallel to the wind direction. The blades of the rotor are arranged rigidly in a plane, that is always oriented perpendicular to the wind. These turbines generally have an eclosed part or nacelle that houses all of the wind turbine's mechanical infrastructure such as the generator, gearbox, break, and power electronics. While most smaller wind turbines have a tail, tails are not common on larger turbines. All horizontal axis wind turbines are mounted on top of a tower, which is either tubular or lattice frame in design.

Wind Turbine Performance

For any location with a known wind resource, there are several factors that can be used to predict electrical generation from a wind turbine. The most important include the power curve, the cut-in wind speed, the rated wind speed and power output, and the cut-out wind speed. These factors along with turbine availability all contribute to the capacity factor of a turbine. All of these terms are explained in more details as follows.

Wind Turbine Power Curve

The main way to assess the performance of a wind turbine is through the examination of a wind turbine power curve, (see in Figure 1). On the vertical axis, the power curve depicts the expected electrical output of the turbine, at specific wind speeds, which are shown on the horizontal axis. Wind turbine power curves can be calculated either based on the design of the turbine, or measured from actual turbine operation. For smaller permanent magnet generators it is especially important to get a measured power curve from a manufacturer since this curve can be different from the calculated version. Furthermore, a power curve is not universally valid. It depends on turbulence, atmospheric pressure, and ambient temperature at the measuring location. A power curve is usually corrected to sea level and 68°F ambient temperature.

Cut-in Wind Speed

The lowest wind speed at which the turbine will generate power is called the cut-in wind speed. Although at face value this parameter should be clear, there are several nuances. Because of the mass of the rotor, a spinning turbine will produce power at a lower wind speed than a turbine starting from a standstill. If the power curve is calculated based on the properties of the turbine, the cut-in wind speed tends to be lower, as it does not account for the rotational mass of the rotor. A low cut-in wind speed is generally desired, since this translates to more time when the turbine is producing at least some power.

Rated Wind Speed and Rated Output Power

The rated wind speed and output power are relative values that give an indication of wind speeds required for the turbine to produce large amounts of power. If the rated wind speed for the turbine is much higher than the typical wind speed for the site, it is probably not a good turbine to use. There will be little time when the turbine is producing significant amounts of power. Usually, a generator with lower rated wind speed is better than a similar one with a higher rated wind speed. This is because the turbine with a lower-rated wind-speed will reach fall rated output under more likely wind speeds.

Cut-out Wind Speed

Cut-out wind speed defines the speed at which the wind turbine is designed to be shut down to prevent damage to the wind turbine. The wind speed is usually monitored by the turbine control system, and if the cut-out wind speed is reached, the turbine braking system is applied and the turbine will not operate. Typical cut-out wind speeds are around 25 m/s (56 mph). By oversizing specific components, wind turbines can be designed to have higher cut-out wind speeds. Small wind turbines with furling mechanisms do not have a cut-out wind speed. Instead, as the wind speed increases, the furling mechanism engages, turning the turbine rotor out of the wind, and thus reducing the turbine strain and power output.

Survival Or Maximum Wind Speed

The survival wind speed is the maximum wind speed that the wind turbine is designed to withstand safely. Most wind turbines have a specified survival wind speed of 50 m/s - 65 m/s (112 mph - 145 mph), and in many cases this value is regulated by national standards. Wind turbines can also be specified to have higher survival wind speeds for installations in unusual or special environments. Small wind turbines with furling mechanisms will still be generating power up to the survival wind speed, while non-furling turbines will not be operating at wind speeds higher than the cut-out wind speed. The survival wind speed is really more of an insurance or a safety consideration, as wind turbines typically do not suffer any damage from winds higher than the stated survival speeds.

Availability

Availability describes the amount of time that a wind turbine is ready to produce energy. It is defined as the ratio between the number of hours the wind turbine operates divided by the number of windy hours over the same time period. A high availability describes a turbine that is producing power whenever the wind is blowing. Availability is a term used to describe the operational and maintenance condition of the wind turbine. In modern wind turbines, availabilities over 95% are expected. For small wind turbines, availability over 99% is not unusual.

Capacity factor

Wind turbine capacity factor describes the amount of energy that the wind turbine produces compared with theoretical production if it were running at full, rated power. The capacity factor is reported over a fixed time period, usually a month or a year, and is calculated by dividing the turbine's energy production over that time by the energy production if the turbine were running at rated power over the same time period. Capacity factor describes the power production expectations of the wind turbine. It is most strongly related to the wind resource at the site. Capacity factors of 25%-40% are typical, while values up to 60% have been reported.

Wind Turbine Types

As would be expected with any power generation technology, not all wind turbines are created equal. Additionally, specific design features make some turbines more appropriate for remote or Alaskan installations. One of the primary problems with wind turbines installed in rural Alaska during the 1980s (many remains of which can still see be seen), is that little thought was given to appropriate application of the turbines or the long-term sustainability of the projects.

Wind Turbine Class And Certification

The International Electro-Technical Commission (IEC), an international standards development organization, has developed a classification system for wind turbine systems. It specifies the design conditions for particular wind turbines. Class I, II, and III specify the design wind speeds for a specific turbine product. Manufacturers who are certifying wind turbines must pick one of these classes.

Class I turbines are designed to operate in the harshest climates, with strong annual average wind speeds and turbulent wind. Class II turbines are designed for most typical sites and Class III turbines are designed for low wind resource sites. Typically Class II and III turbines have a larger turbine rotor (longer blades) to capture more of the wind energy at lower wind speeds. They may look more appealing from an energy capture point of view, even at high wind speed sites; but this should not encourage people to install higher class turbines for lower class sites. The class of wind turbine should be selected based on the conditions at a particular site.

The IEC has also developed standards for many other parameters, such as power performance, noise, and electrical characteristics. Most large wind turbines have been certified to IEC standards; however, this is not as common for medium wind turbines, due in large part to the cost. Turbine Class and certification should be considered when selecting a turbine.

Turbine Design Types

Interconnecting a wind turbine into a remote or weak grid network can be complicated, and specific wind turbine design characteristics play a key role in determining just how hard the job will be. Traditional wind turbines with a synchronous generator, stall regulated control, and no power electronics can cause large power spikes and/or power variability depending on the wind conditions or during start-up. Turbines using synchronous generators but active pitch control allow better or smoother power quality. Variable speed wind turbine technology with active pitch control can actually allow the control system to specify a desired power output from the turbine, as opposed to being limited to accepting whatever energy the turbine produces. Additional devices may also be purchased to smooth out power fluctuations from the wind turbines, such as capacitor banks, turbine soft starts, and variable motor drives. In any case, the turbine selection process should consider the level of turbine and power quality control depending on the application and system requirements.

Other Design Selection Criteria

A multitude of other selection or design criteria should also be considered when determining the turbine model for a particular application. Turbine weight and installation height will be determined by the equipment available to move and install the turbine. Tower type (lattice or tubular, tilt-up or crane-installed) will depend on the site conditions and manufacturer's options. Some turbine manufacturers have cold weather packages that allow turbines to operate at lower temperatures and in icing conditions. Finally, there are applications where it makes sense to install an older turbine, which may have lower performance and limited control options, but which can be maintained more easily in rural areas rather than to purchase a modern turbine, which will have better specific performance and advanced control, but may be more difficult and costly to service.

Wind-Diesel Applications

Wind-diesel power systems can vary from simple designs, where wind turbines are connected directly to the diesel grid with a minimum of additional features, to more complex systems. Two overlapping concepts define the system design and required components: the amount of energy that is expected from the wind system (system penetration) and the decision to use thermal loads and/or a storage device to remedy system energy fluctuations. Given today's technology, these issues are usually determined by the system designers as a starting point for overall system design. These concepts are described in the following section.

When incorporating renewable-based technologies such as wind onto a diesel grid, the amount of energy that will be obtained from the wind resource relative to the diesel generators must be determined, because this will dictate which components will be used. A three level classification system has been developed that defines different levels of penetration on the grid. These classifications, defined as low, medium, and high penetration, separate systems along power and system control needs (see the table on the following page).

Kotzebue Wind Farm

Renewable Penetration

Table 1: Penetration Class of Wind-Diesel Systems (Proposed by Steve Drouilhet)

Penetration Class	Operating Characteristics	Penetration	
		Instantaneous	Average
LOW	• Diesel runs full-time • Wind power reduces net load on diesel • All wind energy goes to primary load • No supervisory control system	< 50%	< 20%
MEDIUM	• Diesel runs full-time • At high wind power levels, secondary loads are dispatched to insure sufficient diesel loading or wind generation is curtailed • Requires relatively simple control system	50% – 100%	20% – 50%
HIGH	• Diesels may be shut down during high wind availability • Auxiliary components are required to regulate voltage and frequency • Requires sophisticated control system	100% – 400%	50% – 150%

Wind-Disel Power System Configurations

Low-Penetration Systems

The wind farm in Kotzebue is one of many low-penetration systems that have been installed worldwide. Low-penetration systems vary from small to relatively large isolated grids. Some large grids, such as those found in certain areas of the United States and Europe, reach a wind power penetration that would classify them in the same category as low-penetration systems. In low-penetration systems, the wind turbines act as just another generation source, requiring no special arrangements.

The control technology required at this level of generation is trivial, especially given the control, flexibility, and speed of modern diesel and wind systems. In many systems, no form of automated control is required; the wind turbines act under their existing controllers, and an operator monitors all system functions. Because the diesel engines are designed to allow for rapid fluctuations in power requirements from the load, the addition of wind has very limited impact, if any, on the ability of the diesel control to supply the remaining difference. Issues of spinning reserve, a term used to represent the availability of instantaneous system capacity to cover rapid changes in system load or energy production, are addressed by the allowable capacity of the diesel engines, which in many cases can run at 125% rated power for short periods of time with no adverse impact.

Medium-Penetration Systems

Systems with larger ratios of wind power fall into this category. The concept is that by allowing power penetrations above 50%, any under-loaded diesel generators in power plants consisting of multiple generators will be shut off and, if necessary, a smaller unit will be turned on. This in turn will reduce plant diesel consumption and diesel engine operation. It might also make the system vulnerable to potential shortfalls, assuming the loss of one or more of the wind generators or diesel engines. In addition, with a large penetration of energy being produced by the wind turbines, it will become harder for the operating diesel units to tightly regulate system voltage and maintain an adequate power balance. There are options to insure that the high-power-quality requirements of the power system are maintained, even with half of the energy provided by wind. Some of these options include power reduction capabilities within the wind turbine controller, the inclusion of a secondary load to insure that no more than a specified amount of energy will be generated by the wind, installation of capacitor banks to correct power the factor, or even the use of advanced power electronics to allow real-time power specification.

Spinning reserve on medium-penetration power systems requires experience with regard to proper power levels and system commitments, but is not considered technically complex. Such spinning reserve issues should be handled on a case-by-case basis. They can be partially resolved through the use of advanced diesel controls, the installation of a modern, fuel-injected diesel engine with fast start and low-loading capabilities, controlled load shedding or reduction, power forecasting, and proper system oversight. Combined with the use of variable-speed or advanced-power conditioning available on many modern wind turbines, the control requirements of medium-penetration systems are relatively simple. The ability to provide high power quality in medium-penetration power systems has been demonstrated for years in a number of critical locations. The most notable examples are the military diesel plants on San Clemente Island and Ascension Island, and the power systems in Kotzebue, Toksook Bay and Kasigluk, Alaska. All of these systems have experienced power penetration at or above the guidelines set for medium-penetration systems.

High-Penetration Systems

Although demonstrated on a commercial basis, high-penetration wind-diesel power systems require a much higher level of system integration, technology complexity, and advanced control. The principle of high-penetration systems is that ancillary equipment is installed in addition to a large amount of wind capacity (up to 300% of the average power requirements), so that the diesel can be shut off completely when there is an abundance of wind power production. Any instantaneous wind power production over the required electrical load, represented by an instantaneous penetration over 100%, is supplied to a variety of controllable secondary loads. In these systems, synchronous condensers, load banks, dispatchable loads (including storage in the form of batteries or flywheel systems), power converters, and advanced system controls are used to insure power quality and system integrity. Spinning reserve is created through the use of short-term storage or the maintenance of a consistent oversupply of renewable energy. Although these systems have been demonstrated commercially, they are not yet considered a mature technology and have not been demonstrated on systems exceeding 200 kW average load. Wind-diesel systems that employ the high-penetration system are operating in St. Paul and Wales. Because of the large overproduction of energy, high penetration wind-diesel systems are economically feasible only if there is a use for the additional energy generated by the wind turbines. In the case of Alaska, this extra energy can be used to heat community buildings and homes (thermal energy), displacing fuel oil. Another use could be to power electric or hybrid cars, ATV's, and snow machines.

Storage use in high penetration wind applications

Until recently, it was assumed that high penetration wind-diesel systems without storage were only theoretically possible. This is no longer the case. Commercially operating short-term storage and no storage systems have been installed in recent years, demonstrating that both technology choices are viable.

In systems incorporating storage, the storage is used to cover short-term fluctuations in power. During lulls in wind generation, the battery bank or other storage device supplies any needed power. If the lulls are prolonged or the storage becomes discharged, a diesel generator is started and takes over supplying the load. Studies have indicated that most lulls in power from the wind are of limited duration, and using storage to cover these short time periods can lead to significant reductions in the consumption of fuel, generator operational hours, and generator starts. The storage system does not necessarily need to be able to carry the full community load, since in larger systems the storage is only used to smooth out lulls in wind energy or to buy enough time to start a standby generator. In these cases, the storage capacity should be approximately the same size as the smallest diesel and have an accessible capacity up to 15 minutes.

In wind-diesel applications, the requirements for storage systems will depend on local wind resources, the costs of different components, capacity and power response times, and the power system performance required. Different storage options are discussed in a separate section of this report, but care should be taken to insure that the storage technology selected meets the specific needs of the particular wind-diesel application.

All high-penetration systems, with and without storage, have been installed in northern climates where the extra energy can be used for heating buildings or water, displacing other fuels. In these systems, it may be wise to install uninterruptible power supplies (UPS) on critical loads. Although only a limited number of systems have been installed, the concept is economically attractive and has the potential to drastically reduce fuel consumption in remote communities in Alaska.

The development of a wind-diesel project can be a complex process, but with a wind resource indentified, the first step of the process is already completed.

Initial Site Selection

The next step is to assess the land availability in conjunction with the wind resource map. The Alaska Wind Map can be downloaded from the AEA web site. This map covers most of the state and can be used as an initial guideline of where to look, but it should not be considered completely accurate. Since the wind turbine needs to be connected to the existing grid and have good road access, sites close to the road, river, and/or power lines are preferred. Once several potential sites have been identified, they should be surveyed by a wind energy or wind resources assessment specialist. The sites should then be ranked based on a number of general criteria, such as:

- Likely wind resource (higher the better)
- Limited environmental impact
- Siting constraints including land availability, land cost, proximity to the airport, accessibility, and historical significance
- Proximity to the power plant and electrical distribution
- Geotechnical considerations

At http://www.awea.org/sitinghandbook/ more information on siting can be found.

Detailed Resource Assessment

Following identification of the most likely sites for wind turbines, an anemometer tower should be installed. Typically, the anemometers are installed at the planned wind turbine installation height. For most small to medium-sized communities a 30 m (~100 ft) anemometer tower should be sufficient. Larger communities may want to install taller towers. If there are multiple high quality sites that are not in close proximity, multiple anemometer towers may be needed. On their website, AEA has resource data for a large number of Alaskan communities, but in most locations site specific wind data collection should take place for a period of one year before project financing is obtained.

Detailed Load Assessment

The second key piece of data is the current and expected load for the community. This information can initially take the form of a daily total generation log. As the assessment process becomes more detailed, it will become important to have time series data representing a full year, in a minimum of one hour increments. This load data should take into account any new plans for the community, such as new buildings or services, as well as standard load growth. Generally speaking, load data should be collected at the power plant bus bar and should be an average reading as compared to a series of instantaneous measurements.

Development Considerations

Other factors play into the decision to implement a wind-diesel power system. One important factor is the age and condition of the existing diesel plant. As introduced previously, wind is a variable resource, and if harnessed it needs to be combined with other base load generation technologies. In most remote Alaskan communities this means diesel generators. Diesel generators are specifically designed to provide power to a fluctuating load. They are a perfect match to the fluctuating power produced by a wind turbine.

As discussed in the section on wind penetration, if the amount of wind relative to the load, and thus the number of operating diesel engines, is small, then older diesel technology will be able to handle the inherent variability in the load and wind generation. As wind penetration increases, the controls of older diesels are not able to react as quickly as needed.

Additionally, the fuel performance of older diesels drops off more rapidly at lower loads. The efficiency of these diesels suffers as more energy is produced by the wind turbines. This limits the amount of diesel fuel that can be offset by the wind turbines. In contrast, modern fuel-injected diesel engines with electronic controls can maintain high efficiencies even at low load levels and should be employed for all higher wind penetration systems. It should be noted that the majority of diesel engines deployed in Alaska are fuel-injected with electronic controls that help to manage efficiency.

A second consideration is the overall age of the diesel powerhouse and associated switchgear and controls. As with any new energy project, integrating new equipment into an old power house is problematic, especially when this integration involves shutting down power to the community. In low penetration applications, the additional control panels and integration are probably not a significant concern, however, as the level of desired wind penetration increases, these integration and switchgear issues become more complicated. For this reason, if the intention is for wind energy to become a major supplier of energy to the community, thought must be given to the state of the diesel plant and to a complete replacement of the whole power system, diesel engines and all.

A community should also carefully consider the motivation behind moving to wind generation. Usually, the cost of energy is a key driver; however, this is only one of the issues to be studied. Other important issues are the environmental impact of energy generation, the price volatility of the 'fuel' used to create that energy, the security of the resource supply, as well as the personal feelings of community members. Ultimately, the purchase of new power generation equipment is a long-term commitment and may not result in near-term reductions in the cost of energy. While wind turbines themselves are not more complex in regards to maintenance and operations compared to diesel generators, the integration of wind turbines into a diesel system can add to the overall complexity of the the entire system. A strategy for ensuring long-term success must be developed beforehand.

System Analysis: While wind does not require fuel as a resource, the costs associated with installing a wind generation system are significant. Determining if the price of harnessing free energy makes sense is key to deciding how much wind, if any, to incorporate into a community's power system.

Using the data collected it is possible to assess different power system configurations and different scenarios for load, fuel prices, wind penetration, and equipment cost. A software tool like the HOMER model produced by the National Renewable Energy Laboratory (NREL) (www.nrel.gov/homer) is a good tool to conduct these initial assessments. Another available screening tool is RETScreen, developed by the Department of Natural Resources Canada. Both tools have their individual qualities that have been evaluated depending on the project needs in the early phases of assessment. It should be noted that as different options are assessed, care must be given to insure that all key parameters and system efficiencies are properly considered. Organizations like AEA or private consultants can assist with this analysis.

As the project develops, more detailed technical and economic assessments will be required. For example, if initial analysis indicates that 500 kW of wind energy is optimal, consideration of which turbines could be used would be based on the available land area. This, in turn, will better define the cost of the required infrastructure and turbine foundations, which can then be used to update the system cost calculations and performance modeling. At this stage, more detailed performance modeling using software such as the Hybrid2 model (http://www.ceere.org/rerl/rerl_hybridpower.html) also developed through NREL, should be considered.

Environmental Assessment

As with any development project in a community, environmental impact is expected and must be assessed. The installation of a wind turbine may impact birds, local wildlife and, fauna, directly or indirectly. These impacts can be clear and easily documented and mitigated; however, some impacts are more difficult to quantify.

Environmental impacts will be site specific, and a site environmental survey should be conducted at any location considering wind power generation. Depending on the source of funds, different levels of environmental impact study are required. The total environmental impacts of any project should be understood in relation to those of other energy options. Results of any environmental survey should be discussed openly so that all options to minimize these impacts are considered.

Many factors play into the assessment of cost of energy from wind systems. The assumed cost of diesel fuel and the potential level of wind penetration are key parameters that must be considered. The higher the penetration, the more the potential fuel savings, but it is not until diesel engines are shut off, or until a shift to smaller and/or more efficient diesels, is made, will large fuel reductions be possible. Nonetheless, in operating low to medium penetration systems in Alaska, fuel savings as high as 25% have been recorded, and higher fuel savings are technically feasible. The potential of these fuel reductions resulting in a lower delivered cost of energy to the consumer will depend greatly on the cost of the diesel fuel, the capital costs of the project, and more specifically on how much of that cost must be borne by the consumer.

The following list includes turbine manufacturers who have equipment installed or being considered for installation in Alaska. Many other manufacturers have turbines on the market. It may be appropriate to look at those products if they have a proven track record in similar operating conditions.

Manufacturer	Device	Website	Size	Notes
Entegrity wind systems	E15/50	http://www.entegritywind.com/	50 kW	Turbine max power is closer to 65 kW
Northern Power Systems	Northwind 100	http://www.northernpower.com/	100 kW	
Various	Vestas – V27	Various	225 kW	Remanufactured turbine
Various	Vestas – V15/17	Various	65/75 kW	Remanufactured turbine
General Electr ic	GE 1.5s	http://www.ge-energy.com/businesses/ge_wind_energy/en/index.htm	1500 kW	
Various	WindMatic	Various	65 kW	Remanufactured turbine

Turbine availability is also an issue, given the strong market for wind turbine technologies outside of Alaska. At present only a small number of manufacturers are building medium-sized wind turbines in the of 50 kW to 1000 kW range. This limits their availability. A supply of remanufactured wind turbines in this range is available, however, presenting another option. Remanufactured turbines, often units that were installed on American or European wind farms in the mid to late 1980s and 1990s, are now being replaced with bigger turbines. In most cases, these turbines are refurbished to the original manufacturers specifications.

Unlike rebuilt turbines, remanufactured ones are usually outfitted with more modern, and higher performance blades, breaking systems, and controllers, as well as with performance monitoring equipment. In considering remanufactured wind turbines, care should be taken to insure that a specific remanufacturer has a strong track record and can provide ongoing and long-term service and/or support. Most high quality remanufactured turbines come with a limited warranty. System developers should not purchase used wind turbines and conduct the rebuild or remanufacture process themselves.

The following describes the current use of medium to large scale wind development in Alaska.

Existing systems:
Chevak
Delta Junction
Hooper Bay
Kasigluk
Kotzebue
Nome
Saint Paul Island
Savoonga
Selawik
Toksook Bay
Wales

Several additional large wind projects, such as the Fire Island project along the Railbelt, are in development but not yet under construction.

The Alaska Center for Energy and Power (ACEP) at the University of Alaska is also in the process of developing a Wind-Diesel Applications Center. This Center would represent a partnership between ACEP, AEA, several other state organizations involved in wind-diesel technologies, and NREL. The Center's mission would be to advance technology in wind energy and wind-diesel integration for the benefit of Alaskans.

Case Study #1: Saint Paul Alaska

In 1999 a high-penetration, no-storage, wind-diesel power system was installed by TDX Power and Northern Power Systems to run an industrial facility and airport complex on the island of St. Paul in the Bering Sea. The project was largely privately funded and initially included a 225 kW Vestas V27 wind turbine. This project was later expanded and now includes three V27 turbines, two 150 kW Volvo diesel engine generators, a synchronous condenser, a 27,000 liter insulated hot water tank, approximately 305 m (1,000 feet) of hot water piping, and a microprocessor-based control system capable of providing fully automatic plant operation.

The electrical load for this industrial facility averages about 70 kW, but the system also supplies the primary space heating for the facility, using excess power from the wind generators and thermal energy from the diesel plant. When the wind generation exceeds demand by a specific margin, the engines automatically shut off, and the wind turbine meets the electrical demand with excess power diverted to the hot water tank.

When wind power is insufficient to meet the load, the engines are engaged to provide continuous electric supply as well as energy to the hot water system as needed. The total 500 kW wind-diesel cogeneration system cost approximately $1.2 million. According to TDX, the system has eliminated $200,000 per year in utility electric charges and $50,000 per year in diesel heating fuel.

The operating wind turbines have had a capacity factor of almost 32% and good turbine availability following an initial problem with the original turbines' generator. The average penetration for this system has been almost 55%, with significant times when the system operates with both of its diesel generators off. Since January of 2005, wind energy has saved over an estimated 150,000 gallons of diesel fuel, about 50% of the expected consumption without wind energy.

V27 Wind Turbines on St. Paul Island.

Case Study #2: Toksook Bay

Toksook Bay is a coastal community located on the Etolin Strait, approximately 115 miles northwest of Bethel. This system was installed in the summer and fall of 2006 as part of a complete plant retrofit by the Alaska Village Electric Cooperative. The town has a population of approximately 600 people, but it is interconnected through the land-based interties to the nearby towns of Tununak and Nightmute, bringing the total population served to over 1,160. The average load of all three communities is just under 370 kW. The power system includes three Northern Power Systems Northwind 100kW turbines, diesel engines, and a computer-controlled resistive heater supplying community heating loads.

The array of wind turbines has had an average net capacity factor of 26.0% from August 2007 to July 2008 and good first year turbine availability of 92.4%. The average penetration for this system has been over 24.2%, with average monthly penetrations over 30% during winter months, when stronger winds prevail. In the year ending September 2008, almost 700 MWhrs of electricity were generated by wind, offsetting almost 46,000 gallons of fuel.

Northwind 100 Turbines at Toksook Bay.

Wind Working Group Recommendations

The wind working group discussed tasks of interest for wind development in rural as well as urban areas. The working group agreed that wind development challenges exist and have to be addressed. Some of the technical challenges have been outlined above. Additional areas in need of further study were identified as follows:

- Identify different business structures that facilitate and optimize wind projects in rural and urban energy environments.
- Identify options and discuss the possibilities and cost of using excess wind energy for heating and transportation fuel displacement.
- Identify the social impact of community wind development.
- Create a database of locally available wind turbine models and system components.
- Identify and list research and development needs.
- Further study wind integration issues in larger grids, especially in conjunction with large hydro installations.
- Identify the Railbelt wind development potential in regard to viable project locations.
- Approach residential wind issues separately, but they should be studied when a larger impact on small community grids is apparent.

There is clear interest and motivation to add wind technologies to the options available for providing energy services to remote communities in Alaska. Although wind or any other renewable technology is not going to replace diesel technology in the near term, it is a valid option and should be considered for communities that have access to a reasonable wind resource.

The development of a wind-diesel power system or the incorporation of wind technology into an existing diesel power system is possible as can be seen by the recent history of projects installed around the state. At present, there are quite a few working examples and a large reservoir of resident expertise that can be tapped to improve future installations.

Costs and benefits must be assessed on a project-by-project basis. The economic impacts must also be weighed against other benefits of using wind technologies, such as reduced risk to fuel price volatility, environmental impact, and energy security. It must also be understood that although wind is a commercial technology, its application in Alaska will continue to be challenging.

There are over 300 remote, diesel power stations in rural Alaskan communities, only 10 of these incorporate wind. This offers a great deal more experience to be gained in Alaskan wind applications. Nonetheless, the track record of wind integration at all penetration levels indicates that this is clearly a technology that is applicable for many of Alaska's rural communities, as well as for those along the Railbelt.

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Web based resources:

Alaska Energy Authority, wind energy program: http://www.aidea.org/aea/programwind.html

Danish Wind Industry Association guided tour and information on wind energy and wind turbine siting: http://www.windpower.org/en/tour/

HOMER power system optimization model (www.nrel.gov/homer)

Hybrid2 power system assessment model (http://www.ceere.org/rerl/rerl_hybridpower.html

National Renewable Energy Laboratory, National Wind Technology Center: www.nrel.gov/wind/ Wind Powering America: http://www.windpoweringamerica.gov/small_wind.asp

Biomass Energy Technologies

AEA Program Manager: Ron Brown (771-3064)

TECHNOLOGY SNAPSHOT: BIOMASS	
Installed Capacity (Worldwide)	Globally, biomass is the fourth largest energy resource after coal, oil, and natural gas. Uses: heating, cooking (biomass), transportation (biofuels), and electric power generation (biopower). NREL estimates 278 quadrillion BTUs of worldwide installed biomass capacity. EIA estimates >2.8 quadrillion BTUs of U.S. biomass energy consumption (2004)
Installed Capacity (Alaska)	Biomass – (heat & cooking) widely used Biopower - 0 kWe (currently no commercial installations) Biofuels – (biodiesel, ethanol) demo projects
Resource Distribution	Potentially available to communities in all regions of Alaska with adjacent or transportable biomass resources. Alaska has >10 times more unused biomass energy resource potential than needed to offset all its diesel fuel used for power production in rural Alaska.
Number of communities impacted	100+ SE Alaska and Interior
Technology Readiness	Biomass – commonly deployed (heat) Biopower – Pre-commercial to early commercial. Biofuels – limited deployments (fish oil/biodiesel)
Environmental Impact	With proper management, impact on local forest land and species is generally considered to be positive. 1.5 million acres are lost annually to wildfire in Alaska, and thinning reduces fire risk.
Economic Status	High confidence in cost savings and localization of benefits for heat. O&M creates local jobs and savings. Bio-Power has high projected cost with limited potential at this time.

Biomass energy, in the form of heat and power, is created by the combustion or gasification of carbon-based plant matter. Biomass energy is considered demand energy, available as/when needed. Woody biomass is the most commonly used form of biomass fuel. It is used directly as firewood, or it can be processed into woodchips or densified into pellets or bricks. Woody biomass is inherently a distributed resource: finding, acquisition and gathering, stacking, and storage are the initial challenges with biomass fuel.

Processing biomass ranges from the simple (bucking logs into suitable lengths), to chipping or chunking (chippers are commonly available machinery), to the more complex (densification that involves chipping, drying, and compressing biomass into pellets, bricks, or logs). As the levels of complexity rise, the benefits of proper handling and storage of the fuel become more pronounced.

Hydronic (hot water) furnaces and boilers combust stick-wood to heat water or other fluid, which can then be transported and used nearby as district heating for buildings, for example, or process heat for manufacturing.

Alaska has nearly 12 million acres of available forested land, with an estimated 1.9 million cords (3.7 million tons) of annual growth. On average, over 1.5 million acres per year of forested land are subject to wildfires and beetle-kill. Some of the wood on these affected lands is salvageable as biomass fuel. Alaska grows substantially more biomass than it uses for energy.

Despite the obvious opportunities, there are also significant transportation and technical challenges related to the deployment of biomass energy devices in Alaska's urban or rural communities. Some challenges are common to installations in any location, while others are more specific to Alaskan off-road communities (see box).

Transportation and Technical Challenges to Biomass energy:

- Environmental concerns, especially those related to air quality and the health impact of smoke from inefficient heating systems in small communities must be addressed. Efficient stoves and boilers required by federal regulations are more expensive than many people can afford. Less efficient devices are common in remote communities. As opposed to individual user systems, community-scale and industrial-scale systems for heat or power are easier to regulate and present less of a threat to health.
- Biomass is a high-volume fuel requiring handling equipment and protected storage facilities.
- Many Alaskan rural communities are in severe physical environments and have limited human resources for technical operations and maintenance of complex or hazardous equipment.
- Heat and power are essential needs, especially in winter. Equipment breakdowns and technical challenges are magnified in these communities, so diesel backup is necessary.
- Sustainability of forest resources is a sensitive and essential issue involving the cooperation of many stakeholders.

In addition to providing savings over diesel, harvest and utilization of biomass can benefit communities in other ways:

- Properly designed forest land use can lessen risks of wildfire and improve wildlife habitat.
- Higher quality logs can be used for house logs or milled into lumber; lower quality material can be used for energy.
- Wood harvest and marketing for energy provides jobs and keeps money in the community.

Larger scale wood-fired power systems are quite common throughout Europe, the United States, and Canada, especially at forest-products manufacturing facilities, places that have the basic ingredients for economic and technical feasibility: large demand for power, heat required for lumber drying or other processes, and plentiful wood waste that needs to be disposed or used. Conventional biomass-fired plants totaling over 60 MW in capacity operated at pulp and sawmills in

Greenhouse at Dry Creek heated with wood. The hydronic fin tube and piping run underneath the plant platforms.

Ketchikan, Sitka, Metlakatla, Haines, and Klawock into the 1990s. Retrofitting and re-permiting existing coal power plants to co-fire wood and other biomass represents another common bioenergy alternative in the Lower 48. In Alaska, Eielson Air Force Base's coal power plant co-fired densified paper separated from the Fairbanks borough waste stream until 2007.

Stand-alone, small biopower or combined heat and power (CHP) technology is generally considered pre-commercial in the U.S. While European and Asian firms have commercial experience and demonstration projects abound in the Lower 48, most systems are complex and have significant technical and economic challenges.

Cordwood is commonly used for heating throughout Alaska. Cordwood-fueled community-scale heating systems have been demonstrated in several communities in Alaska, in Dot Lake and Tanana, for example. A woodchip-fired school and community pool heating system was recently installed in Craig, and that heating system has been considered for other communities as well.

Biomass technologies appropriate for Alaska fall into in three categories:

1. Domestic heating appliances like stoves and small boilers;
2. Community-scale heat and/or power systems based on boilers or engines
3. Larger-scale power generators based on steam or wood gas.

Small, wood-fueled Combined Head and Power (CHP) systems are planned by Chena (400 kW) and by the Alaska Cold Climate Housing Research Center (CCHRC) in Fairbanks (25 kW).

Other systems such as fuel cells are not included in this discussion, because they are still in early stages of development and not close to commercialization.

Wood is composed of several chemical components that react differently when burned. In a wood fire approximately 80% of the solid wood or volatile matter converts to gas before it burns. This gas made up of carbon monoxide and hydrogen is commonly called producer gas or wood gas. If it is burned directly in a stove or furnace, its heat is transferred directly to the living space or to water where its heat can be distributed to buildings by means of hot water or steam.

Producer gas can be separated from the solids and burned as a fuel gas. Producer gas must be used close to the source because of its low heating value and low energy density. This gas has only 15% of the heating value of natural gas or propane, but it can be burned directly in boilers, as a fuel gas in engines, or externally to heat other heat transfer devices such as Organic Rankine Cycle (ORC) fluids or Stirling engines attached to generators. These devices are currently being developed for generating power at a small scale suitable for applications in Alaska.

As the gas and volatile components of producer gas cool, several components condense to form tars and oils. These oils can be converted to pyrolysis oil, also known as bio-oil, which can be used as a transportable liquid fuel. Technologies for making bio-oil are still in development.

About 20% of wood is in the form of fixed carbon. Fixed carbon converts to charcoal (char) when heated. The charcoal does not convert to gas, but burns in direct contact with air. Charcoal burns at much higher temperatures than wood gas, so it is preferred as a cooking fuel around the world.

With devices that make gas or oil, the char is recovered or burned to provide heat to make producer gas. In a stove or furnace the charcoal burns once the gases have evolved and air is available for direct combustion.

Domestic heating devices and small boilers sometimes use gasification principles to burn the wood efficiently, but in these appliances all the wood is converted to heat. Many older-style outdoor wood boilers (OWBs) are inefficient burners. They cause significant air pollution from incomplete combustion and convert only 35% of the energy available in the wood to heat energy in water. Newer, more efficient boilers burn with a clean stack and convert more than 70% of the energy in the wood to heat in the form of hot water or steam.

Community-scale heat and power systems are usually based on boilers that convert the heat to hot water or steam for distribution. Larger boilers can produce steam at a high enough temperature and pressure to generate power in a steam engine or turbine. Steam engines and small turbines are usually very inefficient, so other fluids and generating devices such as ORC and Stirling engines are under development. In parts of Europe that have extensive district (community) heating systems, some plants are being modified to generate power using gasifiers with engines or furnaces with ORC and Stirling engines.

Large-scale power generators are usually based on wood boilers that can operate at sufficient steam temperature and pressure to make electricity efficiently. A small power boiler, 10 MW, would be enough to power a sizeable town. These systems are not suitable for small villages with moderate heat and power loads and limited technical expertise.

Wood biomass energy devices require a fuel handling system, a combustion vessel (furnace, boiler, or gasifier), ash removal, and general maintenance. In the simplest case of manual loading the equipment is needed to cut, gather, and store the wood; manpower is needed to load the unit regularly.

In chip-fed systems, a chipper is added to the equipment list, a loader to handle woodchips, and a bin and feeder (moving floor and/or auger). Woodchips are more vulnerable to moisture than logs and require protection from weather. In many systems the woodchips require screening for oversized or undersized material, and they are subject to bridging, a resistance to flowing.

Pellet-fed systems require more ‘upstream’ processing to deliver pellets to the system, but less complex fuel handling; pellets can flow. Along with higher delivered cost, all forms of densified biomass have more predictable handling and combustion characteristics than stick-wood or woodchips.

Hydronic (hot water) systems add the costs of water or other fluid tanks, temperature and pressure control systems, insulation, and piping to end-users.

CHP gasification systems require a more complex temperature, pressure, and electrical control system; wood gas cleanup equipment; a generator, turbine or fuel cell; fail-safe switching; and a connection to the electrical grid and/or battery bank.

ORC systems require heat and cooling to create a temperature differential for electric generation. Biomass-fired ORC systems are in development in the United States after the successful demonstration of a geothermal-fired system at Chena Hot Springs. For some time these systems have been in operation in Europe.

The high capital cost and projected operation and maintenance (O&M) costs of CHP systems will likely be feasible only in larger communities with high power demand, high diesel prices, and a way to use the substantial amount of heat from the system. As the technologies are refined and costs are reduced, smaller-scale applications may become feasible.

The sustainability of biomass supplies requires planning and coordination, and it will vary widely by area. Regional facilities that gather and process biomass could become a feasible option for upriver, forested communities to supply fuel to downriver communities. Mobile equipment could be shared by several villages in a region on a rotational basis. Road system communities could also benefit from medium-scale regional facilities.

In order to put together a biomass energy project, the initial information required is heat and electrical consumption estimations and fuel resource availability. Forest biomass resource information has been recently gathered for many areas of rural Alaska.

Mapping Forest Biomass Resources:

Further successful deployment of biomass energy systems requires secure and sustainable wood supplies. Many rural areas do not currently have an existing infrastructure for harvesting, processing, and delivering wood. Communities that could benefit from a wood-fired CHP system must first complete wood supply surveys and organize fuel acquisition and handling plans. It is important that wood harvest operations be planned in the context of overall land use objectives to minimize conflicts with other users.

Environmental Assessment:
Biomass heating or power systems must comply with air quality and waste disposal regulations. Design considerations include the height of boiler stacks and protection of water discharge. Solid residues from wood burning are mostly non-toxic ash and useful as a soil amendment.

Potential reduction in cost of energy

Abundant wood fuel at relatively low cost is the primary source of savings in biomass energy. Savings are highest when available wood fuel is a byproduct of wood processing (lumber mill, wood product manufacturing) as in the case of wood chip boilers. The cost of wood increases and savings decrease where wood fuel is from round wood and forest residue.

Installation and operation costs of biomass energy systems may be higher than diesel or natural gas systems. Operation and maintenance (O&M), insurance, permitting, design, and environmental monitoring costs may be substantial for the earliest biomass installations. The application of lessons learned will reduce costs on subsequent installations.

Biomass heating systems are predicted to offset heating costs in many communities where they are not already in use. Biomass CHP systems could result in long-term reductions in electrical generation costs in communities with appropriate biomass resources, heat and power demand, and escalating diesel fuel costs.

A 2007 study suggests that at $2.25-3.00/gal diesel fuel prices and current technology costs, only larger communities are likely candidates for CHP systems. That list includes Aniak, Dillingham, Fort Yukon, Galena, Hoonah, Tok, and Yakutat. If fossil fuel costs escalate and CHP technology evolves, more small communities may also be come viable candidates. The same study also concludes that woody biomass resources are adequate for fuel requirements in most of the forested communities being considered for biomass systems.

There are several options for heating, fewer for power generation. Listed below are some examples of high efficiency boilers and some new designs for small-scale power generation being used or considered for use in Alaska.

The following list includes developers who, at a minimum, have built a prototype device.

Manufacturer	Device	Website	Location	Level of Development
Garn	High efficiency Hydronic Wood Fired Heaters	www.garn.com	Dot Lake, Tanana, Ionia, Homer (private individual)	Commercial 25 years High fuel efficiency (75.4%), low emissions
Chiptec	Gasifier-boiler	www.chiptec.com	Craig	130 installed 1 - 30 MMBtu
Decton	Chip and sawdust boiler	www.decton.com	Dry Creek	Industrial and community use
Decton	Chip and sawdust boiler	www.decton.com	Kenney Lake Regal Saw Mill	Industrial and community use
Crorey Renewable Resources	25 kW gasifier	www.croreyrenewable.com	CCHRC Fairbanks	Prototype in development, not yet delivered
UTC Power	200 kW Purecycle ORC	www.utcpower.com	Chena Hot Springs	Commercial demonstration with geothermal, biomass project planned for 2009
Danish Stirling	35 kW Stirling	www.stirling.dk	Denmark	Demo
AgriPower	100+kW	www.agripower.com	New York	Demo

Case Study #1: Tanana, Heating System

In November 2007 the community of Tanana installed two cordwood boilers to heat a washeteria with a system similar to one operating in Dot Lake since the late 1990s. Cordwood is burned to heat a large reservoir of water. Wood is burned with 75.4% efficiency at a high temperature for about two hours, twice a day. The water stores the heat and circulates it to the washeteria and other buildings as needed.

The Tanana project represents an efficient method of burning wood. Other boiler systems are now being developed to operate at high efficiency. Compared to the low-efficiency OWBs (Outdoor Wood Boilers), these boilers use half the wood fuel. Many communities could benefit from these systems. They are heat-only systems and have not yet been integrated into CHP systems capable of generating power.

System: Two (2) 1850 gallon hot water boilers, 425,000 Btu/hr each
Manufacturer: Garn, Minnesota
Fuel: cordwood substitutes for 9,000 gallons diesel per year (250 gals/day)
Wood fuel (spruce) at $225/cord is equivalent to diesel at $2/gallon
Schedule: installed November 2007
Budget: $170,000 including photovoltaic solar panels on roof of Washeteria

Assuming 72 cords/yr are necessary to displace 9,000 gal/yr of diesel, increased labor costs of $1,100/yr over the existing oil system, $850/yr for power and other wood system O&M, $225/cord of spruce, and $5.00/gal for heating fuel, annual savings are approximately $26,700/yr. Therefore the simple payback on the initial system cost is $170,000/$26,700; approximately 6.5 years.

Wood for winter heating is piled up along the Yukon River at Ruby.

Case Study #2: City of Craig, Heating System

In 2004 the city of Craig began investigating ways to reduce the cost of heating their community swimming pool and pool-house, as well as their elementary school and middle school. The three buildings are adjacent to one another on city property in the middle of town. One study suggested converting the propane-heated pool to oil (14,000 gallons/year). Further study showed that a woodchip-burning boiler could substitute for both the propane used for the pool and the oil in the schools (~ 24,000 gallons of oil per year). Chipped wood would come from a local sawmill. The project looked feasible with oil at $2.50/gallon, so a detailed engineering design was developed and the boiler was finally commissioned in the spring of 2008. It was turned off in May and restarted in September.

Wet chips are delivered to the 24-ton storage bin (a 10-day supply at 2.2 tons per day). Hot water from the boiler heats air used to dry the chips to the desired moisture content. The wood is burned in a staged combustion system. It is first gasified, and the gas is burned in the boiler. Hot water from the boiler is pumped on demand to heat exchangers at the pool and schools. If the wood boiler failed, the existing propane and oil boilers would continue to supply heat to the facilities. For three months the system required about 8 - 10 hours per week of maintenance time, which included a weekly cleaning. The boiler has excess capacity and may supply additional buildings in the future.

By January 2009, the City of Craig will release a report describing the development of the project. It will probably take another two years to obtain more detailed operating characteristics and costs for the project. Experience in similar Lower 48 installations has shown that it takes time to adapt to the inherent variability of local fuel and heating loads. For example, in 2009 the City will try substituting less expensive hog fuel, a mixture of sawdust and bark, for the more uniformly sized and drier chips currently supplied by the sawmill.

Assumptions and preliminary economics:

- 85% displacement of 22,300 gal/yr of #2 heating oil and 39,000 gal/yr of propane used by the pool and school buildings
- $4.10/gal for heating oil and $2.50/gal propane
- O&M costs of approximately $24,000/yr (1/3rd labor and 2/3rd power and consumables)
- 753 tons/yr of 50% moisture content chips at $20/ton
- 65% efficiency for wood combustion versus
- 70% efficiency of the previous system

Annual savings will be approximately $122,000 per year. Simple payback on the initial system cost is $1,510,000/$122,000, approximately 12.4 years. Given the spare capacity, system economics will improve if the project serves additional facilities. Given an estimated useful project life of 20 years, the economics of the current project are acceptable under the above assumptions.

Lessons learned at this installation can be used to save time and reduce cost in other communities.

System: 4MMBtu/hr gasifier, hot water boiler
Manufacturers: Chiptec (Vermont), Design Engineer: R&M (Ketchikan),
CTA (Missoula).
Fuel: woodchips from Viking Sawmill, Klawock, displace equivalent of 24,000 gal diesel/year.
Schedule: Commissioned April 2008.
Installed cost: $1.51 million

Case Study #3: Village Power, CCHRC 25kW Gasifier Demo

The Cold Climate Housing Research Center (CCHRC) is engaged in a biomass gasifier testing/ demonstration project with a proposed 25 kW gasifier that is being manufactured by Crorey Mechanical in Oregon. It is designed to run on wood chips. The target delivery date was set for October 2008, but the manufacturer is behind schedule. Now it might be ready for shipment after January 1, 2009. The manufacturer has previously successfully field tested units using wood pellets and coffee waste as fuel, but their product has not yet been commercially installed.

The intention is to run the gasifier in tandem with a diesel genset displacing a portion of the diesel fuel. Success with this first test could lead to pairing the gasifier with a spark ignition genset and eventually a microturbine to demonstrate other available options potentially appropriate for specific applications.

The gasifier will be operated and assessed over a testing period and, if successful, CCHRC will then develop a feedstock conveying and drying system appropriate for the Alaskan environment. This will facilitate the subsequent placing of a unit in another remote location for further testing and demonstration.

The first phase of this project is funded by the Fairbanks North Star Borough and the State of Alaska DCED at a level of $300,000. Additional funding will be required for development of feedstock conveying and drying equipment. In addition to this project, CCHRC continues to search for a residential-scale biomass CHP system for testing and demonstration at their Fairbanks facility.

Proposed system: 25 kWe gasifier
Manufacturer: Crorey Mechanical (Oregon)
Fuel: wood chips
Schedule: tentative delivery date of January 2009
Budget: Phase 1: gasifier and testing ($300,000)
Source: Fairbanks North Star Borough
Phase 2: fuel handling ($$ unknown at this time)
Source: Unknown

Case Study #4: Community CHP Fairbanks 400 kWe ORC

United Technology Corporation (UTC) and Chena Power have proposed a biomass/ORC power-generating demonstration project for a site near the community of North P ole. Wood waste and waste paper will be separated from the waste stream and combusted in a Wellons thermal oil heater to deliver heat to a UTC PureCycle 200 power plant module. The boiler is rated at 2.5 MW thermal capacity with an efficiency of 85%. UTC is currently redesigning the PureCycle to operate at 20% efficiency converting heat to electricity, which means that the proposed system could supply up to 450 kWe (net 400 kWe). The system will have excess thermal capacity that can be used for space heating.

Four main components comrise the UTC/Chena Power project:

- Shred-Tech STQ 100 Shredder and Conveyor System
- Wellons Live Floor Feed System
- Wellons 2.5 MW Boiler
- Two UTC PureCycle 200 Power Plants

The shredder reduces the biomass to a uniform size that is easily combustible and delivers it to the live floor. The live floor stores the shredded biomass until it is required by the boiler, at which time the rake and auger system in the live floor feeds biomass into the boiler. The boiler generates heat, which heats thermal oil, which in turn heats refrigerant in the UTC PureCycle 200 power plant. The refrigerant expands and turns a turbine that generates electricity. On the other side of the turbine, the expanded refrigerant is air cooled. It condenses back into a liquid, completing the cycle.

Proposed system: 400 kW
Manufacturer: Wellons, Inc. (Oregon), UTC Power (Connecticut)
Fuel: woodchips, paper, cardboard
Schedule: Projected 2009-2010
Budget: $5 million
Future plans: if a successful demonstration, this technology could be used at other sites
Based on: 400 kW ORC (UTC Power) generator currently in use at Chena Hot Springs

The Working Group agreed that the need for small to medium-sized biomass projects for space heat is critical to help combat the high cost of energy in rural Alaskan communities. They also recommended ongoing research to find suitable biomass technologies for generating power while simultaneously providing space heating in smaller communities.

The Working Group is aware of the impending Alaska Energy Authority RFP process for Renewable Energy Projects and is encouraging communities that have biomass resources readily available to apply. The consensus is that most applications will be submitted for small to medium space heating projects and district heat loops.

The group is interested in seeing wood pellet manufacturing take place in Alaska. Several firms from Outside with years of pellet production experience are looking at developing projects in Alaska, partnering with entities with resources and funding capabilities. The consensus is that wood pellets are desirable because they burn cleanly, and that the appliances and boilers that use them are a proven commodity. Wood pellets are easy to transport and store, and they are the closest fuel to liquid or natural gas that can be easily manufactured in Alaska.

The group also recommends wide promotion of EPA-certified wood stoves to insure efficient wood resource utilization. They also recommend promoting only High Efficiency, Low Emission (HELE) Hydronic Wood-Fired Heaters for larger projects that meet minimum standards for overall efficiency (combustion efficiency x heat transfer efficiency) and EPA particulate standards for emissions.

Left: High Efficient Low Emission GARN hydronic wood-fired heater being tested at Tanana. Twin units will heat the 5,000 sq. ft. washeteria and provide domestic hot water for showers and washing machines. They will also add heat to the community water loop to help deter freeze-ups during winter months.

Biomass CHP systems are in the early stages of development and demonstration. They require more development to perform reliably. Existing systems do not show any savings over systems powered by oil and gas at today's oil and gas prices.

Facilities to manufacture densified biomass fuel (pellets, bricks, and logs) will develop in tandem with deployment of systems for delivery and use of densified fuel.

Biomass for space heating to help reduce trhe high cost of energy in rural Alaska has a high probability of success. The following are requirements for successful projects:

- Projects must be economically viable
- Must be technologically feasible
- Must be supported and endorsed by owner/ operators, the local community, fuel suppliers, and state and local governing bodies
- Must have a local champion
- Must have long term reliable and sustainable fuel sources

Several biomass heating systems are currently in operation as successful examples.

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Geothermal Energy Technologies

AEA Program Manager: David Lockard (771-3062)

Hothouse tomatoes are grown at Chena Hot Springs year round with the geothermal project.

TECHNOLOGY SNAPSHOT: GEOTHERMAL	
Installed Capacity (Worldwide)	approximately 10,000 MW
Installed Capacity (Alaska)	680 kW installed
Resource Distribution	Dispersed resources exist across southeast Alaska, the Interior, and the Aleutians.
Number of communities impacted	Limited
Technology Readiness	Commercial
Environmental Impact	Minimal, small plant footprints, little or no CO_2 emissions, reduced surface flow of thermal springs
Economic Status	Payback of 5 to 8 years expected for the Chena Hot Springs Project, project economics vary widely depending upon size of project and sales price of electricity

Right: Alaska's abundant geothermal sources provide hot water at close proximity.

Geothermal is a general term describing the heat generated and contained within the earth. Over 90% of the total volume of the earth has a temperature exceeding 1000°F, and only a small amount of this heat gets close enough to the earth's surface to be utilized by conventional technology and be considered an energy resource. When it does, the elevated heat manifests itself in uncommon geologic occurrences like lava flows and volcanic eruptions, steam vents or geysers, hot springs, or elevated geothermal gradients creating hot rock. In normal geologic situations, the majority of the heat slowly dissipates into the atmosphere by unseen heat transfer processes known as conduction, convection, and radiation.

At the surface of the earth, heat can also be gained from the sun during daylight hours. The sun, especially during the summer months, can heat to depths of 100 feet. When ground source heat pumps are used for heating buildings, the energy may come from either solar or geothermal sources. Below a depth of several tens of feet, any heat recovered from the earth will usually be geothermal in origin. Geothermal heat comes from two main sources: the original heat of the earth generated at its formation about 4.5 billion years ago and the more recent decay of the radioactive isotopes of potassium, uranium, and thorium.

Geothermal resources are found on all continents and have been used for a wide variety of purposes, ranging from balneology (the science of soaking in hot springs or hot mud baths) to industrial or direct use processes such as space heating, from process heat for drying things like fish or lumber to electrical power generation. Industrial uses require temperatures ranging from 150°F to around 300°F. For large-scale electrical power generation, (measured in megawatts or millions of watts) temperatures in the neighbourhood of 300°F to 650°F are needed. In Alaska with its cold climate and abundant cold water resources it is possible to use much lower geothermal temperatures for small-scale electrical power generation.

In fact at the Chena Hot Springs Resort, 500 gallons per minute of 163°F water is making around 200 kW of electricity, the amount of electricity used by a village of about 300 residents. The combination of high flow rates of hot water and low surface water temperatures in use allow Chena to be the lowest-temperature geothermal power plant in the world.

For geothermal energy to be technically and economically feasible, a number of conditions must be met. These conditions include: (1) an anomalous thermal gradient or accessible heat in a near-surface region, (2) sufficient porosity and permeability within the section of 'hot rock' so that fluids can move freely and transfer heat, and (3) some form of conduit that allows a hot fluid to flow to the surface in sufficient quantities. There the energy can be converted into a usable form. Clearly, the higher the near-surface temperature and the higher the permeability and flow rates, the more feasible the resource becomes. Unfortunately, out of the thousands of natural springs in Alaska, only a few have sufficient temperature and flow rates necessary to produce electricity. In some limited cases where high near-surface heat exists, these fluid flow and heat transfer systems can be enhanced by drilling and fracture technology if geologic conditions are right (see EGS below).

Globally, geothermal resources have been found in four generalized geological environments: areas of active volcanism and igneous activity; areas of thinned continental or oceanic crust; large crustal scale faulting; and some sedimentary basins. Power plant outputs from these geothermal fields vary from about 1 MW to over 700 MW. The most prolific and widespread geothermal resources are contained in areas of dramatically thinned crust and associated igneous activity, such as Iceland and to a lesser degree Nevada and southern California.

With the possible exception of weakly developed rifting on the Seward Peninsula, this geologic environment does not exist in Alaska. Producing tens of megawatts, moderate-sized geothermal resources are associated with linear belts of volcanoes which form when one plate is subducted beneath another. Active Alaska volcanoes like Mt. Spurr west of Anchorage and others along the Alaska Peninsula and Aleutian Islands are subduction-related. Some of these volcanoes host what are apparently the hottest geothermal resources in Alaska.

Other, smaller geothermal systems are closely associated with crustal scale strike-slip fault systems in southeastern Alaska and through the Interior. A complete list of these known geothermal resources can be found at www.dggs.dnr.state.ak.us in publication MP-8.

Hot springs located along large faults in the earth are relatively widespread. These faults can extend well into the crust of the earth. If the fractures remain open under the great amount of pressure, these faults might allow water to percolate more than 2-3 miles deep. If this happens, the water will become hot by virtue of the significant depth reached (a typical geothermal gradient has a temperature of about 270°F at 3 miles depth). If the fault maintains porosity and permeability, this heated water can be forced to the surface (or near surface) and become a geothermal spring.

There are numerous sedimentary basins in Alaska, the most famous of which underlies the North Slope and hosts the Prudhoe Bay oilfield. Excellent porosity and permeability can be maintained in sedimentary rocks at depth, and if the geothermal gradient is sufficient, hot fluid can be produced from these formations. For example, the reservoir temperature at Prudhoe Bay at 7500 to 8000 foot depth is approximately 180°F to 200°F. Depending on the geothermal gradient of the basin and the relic permeability at depth, production of this hot water may become a viable small-scale energy source for oilfield operations, or even for communities in the immediate area. The high cost of drilling and permeability enhancement, along with relatively low geothermal temperatures, makes these resources difficult to economically develop on a stand-alone basis.

In making electricity from geothermal steam or hot water, two basic types of equipment convert the heat energy into electrical energy. If the geothermal fluid temperatures are greater than about 350°F, a conventional low-pressure steam turbine is utilized. As the steam passes through a series of blades known as a rotor, the pressure is reduced. The steam expands, thus spinning the rotor. The rotor is attached by a straight shaft to a generator that spins and makes electrical power. In a few rare places in the world, geothermal production wells flow steam with no water. The steam is transported directly from the well to the turbine. In most cases a mixture of steam and hot water is produced by the well, and the water must be removed with a separator so that only pure dry steam enters the turbine. The geothermal liquid and the condensed steam are sent to an injection well, where they are returned to the reservoir to be utilized again and again. Essentially, a geothermal power plant ‘mines’ heat from a geothermal reservoir.

If the geothermal fluid temperatures are less than about 350°F, a different type of turbine is needed. Instead of steam passing through the turbine, a lower-boiling-point liquid, a working fluid such as isobutene, isopentane, or a refrigerant, is heated in a heat exchanger by the geothermal water. It becomes a vapor and is then sent through a turbine. No water (either as liquid or steam) passes through the turbine in this instance. Once through the turbine, the vapor is condensed and pumped back through the heat exchanger again and again. The geothermal fluid in this case is also returned to the reservoir to mine more heat.

Enhanced Geothermal Systems (EGS)

Most of the earth is not near volcanoes or major active faults so it lacks open space or fractures that can heat the fluids necessary for a shallow geothermal system. The geothermal industry has long known that developable heat exists within drillable depths in most areas of the globe, yet a technically economically feasible way to transfer that heat to the surface in economic quantities has been elusive. If this methodology can be developed, a tremendous energy resource can be tapped. One interesting aspect of this research effort is the use of techniques developed by the oil and gas industry to fracture rocks far below the surface, Huge volumes of fluid are pumped at high pressure into the deep strata. The theory is that once the rocks are broken and permeability is established, it is possible to pump cold water down one hole into hot rocks and recover it from a second hole located thousands of feet away. If all goes according to plan, the water will mine heat from the fracture surfaces between the two holes. It will become hot enough to utilize for direct use and/or electrical power generation. This concept is called enhanced geothermal system, or EGS.

Projects are now operating in France, Germany, and Austria, where six small EGS projects are generating between 0.25 MW and 3.5 MW of electrical power from wells between 7000 feet and 16,000 feet deep and at temperatures from 300°F to 500°F. After the power is generated, additional heat is sometimes removed from the water for space heating as a part of some of the projects. These expensive, government-supported research projects have taken many years to develop. With this experience in hand, Germany has recently announced plans for over 100 future projects with outputs as high as 8.5 MW for some of them. In Australia numerous press releases tout much higher potential megawatt outputs, but no projects are yet on line.

Relatively little is known about the most effective methods for implementing an enhanced geothermal system. Many variables such as the temperatures, the temperature gradient, the type and characteristics of rocks present, and the existing stresses on the rocks, need to be considered in planning an enhanced geothermal project. Within Alaska there must be some areas where the overall conditions are more favorable for such a project than other areas. Each area is unique, and all variables need to be assessed to determine the feasibility of an enhanced geothermal system. Development of enhanced geothermal systems will continue to be mostly experimental in the next years. The EGS concept bears close watching because enhanced geothermal systems could be part of Alaska's future.

Known Geothermal Areas:

Alaska has a number of documented shallow sources of heat along its southern margin and in the central part of the state. For physical and economic reasons many of these resources are under-explored and undeveloped. These known geothermal areas range from modest temperature thermal springs like Pilgrim, Chena, and Manley to large areas of hot springs found on or near active volcanoes. The locations of all major thermal springs in Alaska have been identified, but some lack basic descriptive information such as flow rate and geochemistry. These springs represent a thermal and mass discharge point from a geothermal system that may support development.

Blind Geothermal Systems:

Blind geothermal systems are those without surface manifestations. These systems are the subject of much debate within the geothermal community. Whether blind systems exist in Alaska is unknown at this time. Precious little subsurface temperature data exist to indicate the presence of such systems. Nevertheless, a significant amount of additional geologic information is available to help determine if an area is likely to contain such anomalous features. In the absence of detailed thermal gradient information is impossible to say categorically that small geothermal anomalies do not exist, but substantial supportive geologic information can help in the evaluation of potential areas for exploration.

In order to put together a geothermal power plant project, details about the resource and where and how the electricity will be consumed must be known. In the simplest possible case (similar to the case of Chena Hot Springs Resort), a small amount of power is developed and used within a small area by the owner of the resource. However, ownership is often complicated when the surface and subsurface (including the geothermal resource) are owned by different entities, or when there are numerous landowners in the vicinity of the site.

Developing a geothermal resource includes a number of critical steps that must be strictly adhered to. The first and most important step is that of identifying and characterizing the resource potential and capabilities for economic power generation. The simple occurrence of a hot or warm spring at the surface is not sufficient evidence for a developable resource. The size, flowability, sustainability, and ultimate heat flow are all difficult determinations that must be made with great care. The initial exploration phase can be costly and has a high risk of economic failure.

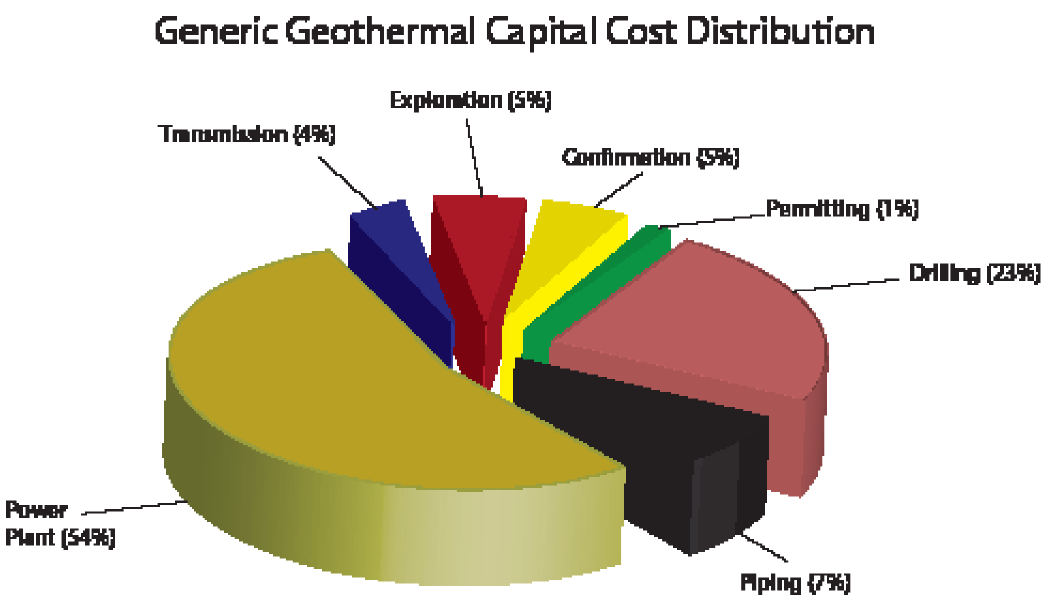
The exploration and development phases needed to characterize and sanction power plant construction will involve procuring permits, expertise, and equipment to collect and interpret data on geology, geochemistry, geophysics, and temperatures, so that wells can be sited and drilled into the reservoir. Once one or more wells have been drilled and the reservoir is identified, flow testing and reservoir engineering assessments are needed to determine the possible size and productivity of a reservoir, and also to determine how the reservoir will be produced and managed. At this time, the power plant can be designed and equipment can be chosen to best suit the reservoir. Adequate financing will be needed for construction of the power plant and any transmission line.

After the power plant is built and in operation, reservoir monitoring and management are needed to optimize the system and to determine strategies for maximizing the life of the resource. It commonly takes ten years from the start of exploration to the commissioning of a power plant for projects exceeding 10 megawatts in capacity. Small projects of $<$ 1 megawatt to 2 or 3 megawatts can be completed in 2 or 3 years.

Operational geothermal power plants have an excellent worldwide record of reliably producing power for decades with modest environmental impacts and low operation and maintenance costs, provided that the resource is properly managed and not overdeveloped.

Potential Reduction in Cost of Energy

Most geothermal resources that could now be developed in Alaska are larger than needed to satisfy local demand, or significantly remote requiring substantial investment in transmission lines. According to the paper, 'Factors Affecting Costs of Geothermal Power Development;' published by the Geothermal Energy Association, capital costs for a geothermal project can be broken down as follows. It is important to note that these relative costs can vary significantly depending on remoteness of the resource and access to equipment and technologies:



Total capital costs, including all elements of development shown in the figure above, ranged from $3000 - $3900 per kW for a large (100MW) plant in 2007 dollars. A smaller plant, such as the one installed at Chena Hot Springs, is expected to cost more. Considering exploration and all other elements of the Chena project, the total capital cost of the project was $6275 per kW.

Operating and maintenance costs for a geothermal power plant are an estimated $15 MW-$30 per MW, or 1.5¢-3¢ per kWh. For the Chena project, O&M costs were calculated at 2¢ per kWh.

Manufacturer Options

The following lis a ist of manufacturers and engineering firms who build geothermal turbines and/or power plants:

Manufacturer/ Contractor	Location	Device Name	Website	Steam Turbine or Binary
Fuji Electric Group	Japan	Steam turbines	www.fujielectric.com	Steam
Mitsubishi	Japan	Steam turbines	www.mitsubishitoday.com	Steam
Toshiba	Japan	Steam turbines	www3.toshiba.co.jp	Steam
Ormat	Israel	Geothermal turbines	www.ormat.com	Both
Rotoflow	USA	Geothermal turbines	www.rotoflow.com	Binary
Mafi-Trench	USA	Geothermal turbines	www.mafi-trench.com	Binary
United Technologies	USA	Geothermal turbines	www.utc.com	Binary
Power Engineers	Idaho	Plant design and construction	www.powereng.com	Both
Geothermal Development Associates	Nevada	Plant design and construction	www.gdareno.com	Both
The Industrial Company	Colorado	Plant design and construction	www.tic-inc.com	Both
Processes Unlimited International	California	Plant design and construction	www.prou.com	Both

Chena Hot Springs

Northeast of Fairbanks, Chena is home to the only operating geothermal power plant in Alaska. See the case study for more information.

Pilgrim Hot Springs

Pilgrim was the site of another Department of Energy drilling program. The resource appears to have development potential using binary power generation equipment, but the source of the geothermal fluid was never identified. Pilgrim is located approximately 50 miles from Nome, and a recent study suggests that if proven adequate, it may be economical to develop the resource to supply power to Nome.

Unalaska

The Makushin geothermal resource near the community of Dutch Harbor on Unalaska (Aleutians) is the only proven high temperature geothermal system in Alaska that could be used for power generation. An exploratory drilling program, which took place in the early 1980s and was funded by the Department of Energy, made this determination.

Akutan

The community of Akutan (Aleutians) is considering options for developing a nearby resource located in Hot Springs Bay, approximately 10 miles from the community.

Naknek

The Alaska Peninsula community of Naknek is conducting a geothermal exploration program.

Manley Hot Springs

Manley, on the Tanana River, is a resource similar to the one at Chena. It has the potential to supply 100% of the power and possibly the heat to the community; however, the project is complicated by land ownership issues.

Mt. Spurr

The Mt. Spurr volcano, across Cook Inlet from Anchorage, is a unproven resource, but its proximity to Anchorage, makes it worth further assessment. Ormat, a geothermal developer and power plant manufacturer, recently won a competitive bid process and purchased all but one lease section on the volcano.

Other regional assessments have been proposed, as well as development of other resources. However, no additional activity has taken place at other sites in the past 10 years.

Case Study: Chena Hot Springs Resort

Chena Hot Springs Resort is a privately owned facility located 60 miles northeast of Fairbanks. Chena is located 33 miles from the nearest electric grid and maintains its own generation facility and approximately 3 miles of distribution lines. Prior to 2006, Chena used diesel engines to supply power to the site, with an average load of 180 kW. In 2006, Chena installed a 400 kW geothermal power plant consisting of two 200 kW PureCycle 200 modules designed and manufactured by United Technologies Corporation. Chena is currently in the process of installing a third 280 kW production model PureCycle 200, for a total installed capacity of 680 kW.

The power plant is unique because it was designed to work using geothermal fluids at 165°F, which is a significantly lower temperature than that of the fluids used at other geothermal sites for commercial power generation. The United Technologies equipment is based on refrigeration components from its subsidiary company, Carrier Refrigeration. Originally designed for industrial waste heat applications, the power plant modules were and modified for this geothermal application. In the winter, the units are air cooled or water cooled (via a cooling pond installed in 2008), and water cooled in the summer. Project capital costs totaled $1,926,962, which was partially offset by a $246,288 grant from the Alaska Energy Authority. This included the drilling of a geothermal production well, but it did not include any exploration costs. Those were partially covered under a Department of Energy grant. The project also used numerous recycled components including 4200 ft of pipeline and a 1.5 MWh UPS system, which reduced the cost of the project significantly.

During its first 27 months of operation, the power plant logged 18,722 hours at 99.4% availability, excluding five weeks of repairs after a fire occurred in the building in May 2007. During this repair period, the unit operated with an average capacity factor of 87%, with an average net output of 174 kW per unit. The reduced capacity factor is due to flow rates on the hot water side averaging approximately 60 gpm below the rate for which the system was designed. When both units are online, this flow rate is further reduced per unit for a total plant output of 280 kW (70% capacity factor). The power plant is designed to be dually cooled, using cold water in the summer, and air or water in the winter. During intermediate seasons, unit output has been reduced as a combined effect of less available cooling water flow and inefficient operation of the air-cooled condensers at temperatures above 0 °F-10 °F. This issue should be mitigated by the installation of a cooling pond in 2008.

Installation of the geothermal modules has resulted in a 50% reduction in gallons of fuel purchased at Chena (compared with fuel purchases prior to the installation during times the power plant was operating). Greater fuel savings have not yet been realized, because the generators were designed to be grid connected, they use induction generators that require a stable frequency and voltage to operate properly. A 1.5 MWh UPS system was installed to provide grid stability, but there were initial problems integrating it into the existing power generation system. This resulted in challenges with completely eliminating the diesel engines and operating both power plant modules simultaneously without overpowering the grid. For this reason, in 2007 and the first half of 2008, only one power plant module was typically in service at a time, and thus actual fuel saving were just half of what was expected. This issue has been resolved, and now both units are operating for a total net output of 280 kW. The third unit, a larger 280 kW PureCycle module, is expected to be online by the end of 2008, bringing the total installed capacity to 680 kW.

Overall fuel offset in the first 26 months of operation was 228,000 gallons for a total savings of $650,873.

Above: The 400 kW geothermal power plant at Chena Hot Springs. Named the Chena Chiller. This unit is unique in that it is designed to work with geothermal fluids much cooler than any other plant.

Right: This artesian well is located at Chena Hot Springs Resort and flows at around 300 gpm.

Facing page top: An old greenhouse at Chena Hot Springs is surrounded by naturally heated water.

Facing page bottom: An injection well is being drilled for the geothermal power plant at Chena.

This takes into account a 116% increase in site load, to an average of 430 kW since installation of the geothermal power plant. This increase is due to the installation of a production greenhouse (75 kW load), the addition of electric appliances in the hotel rooms and restrooms, addition of plug-ins for vehicles, and an increase in site pump loads. Assuming output remains constant, the simple payback at current (2008) fuel prices will be realized in just over 6 years (the end of 2012) from the date of installation. O&M and debt load for the project are currently $73,500 per year. The addition of these values results in a net payback of 8 years from an installation date at the end of 2014. This could be reduced to 5 years if all units are operated simultaneously and greater fuel savings are realized.

Chena is also planning to drill a deeper well in 2009 to access the deeper reservoir to produce higher temperature fluids. This improved efficiency of the power plant will reduce the total volume of water required for operation.

Alaska Geothermal Working Group Recommendations:

- Create regional geothermal development plans to combine resources (drill rig, exploration equipment, expertise)
- Consensus is that power is highest use of geothermal in power generation, however there should also be an assessment of the potential for other uses such as for greenhouses (food production), mineral processing center operation in Aleutians, absorption chilling, and producing alternative fuels. Mineral recovery from geothermal brines is also a possible area for research
- Develop a state drilling program as part of the state energy plan
- Put together set of criteria that helps rank and prioritize projects throughout the state
- Consider ground source heat pumps in areas where appropriate

It could be argued that geothermal energy is one of the most sustainable and environmentally friendly energy resources that can be developed. Unfortunately, geothermal heat needs to be close enough to the surface and in the right geologic setting to make it economically feasible for development. This rare occurrence in Alaska. It is tantalizing to presume that if one drills deep enough there will be a heat resource that can be exploited, but experience in the development of deep subsurface fluid flow systems shows a sobering reality regarding the extreme costs and risks associated with these activities. Nevertheless, in areas where large geothermal resources are present and relatively easily accessible, geothermal electrical power generation has been shown to be cost competitive with large-scale coal, natural gas, or nuclear power generation. In remote areas, such as the islands of Indonesia, Japan, and the Philippines, where other forms of energy are expensive and difficult to come by, geothermal power generation, is the dominant method of power generation and some fields have now been operating for almost 50 years. The primary challenge for developing geothermal power when the potential exists is locating, developing, and managing the resource in an economic manner.

With continued research and development, a wide variety of geothermal power plants has been designed and built to operate on a wide variety of resources with temperatures ranging from 165^{O}F - 650^{O}F. Continued research in areas such as EGS will be important in furthering the value of geothermal energy as a substantial energy alternative.

As new technology is brought forth, the geothermal resources present in Alaska should be constantly evaluated and developed where physically and economically feasible. The remote location of a number of geothermal resources relative to population centers and transmission grid is a difficult hurdle to overcome. In Alaska, developing strategies for using geothermal resources is likely to prove as difficult as actually developing the resources, yet given the potential, this development is well worth the effort.

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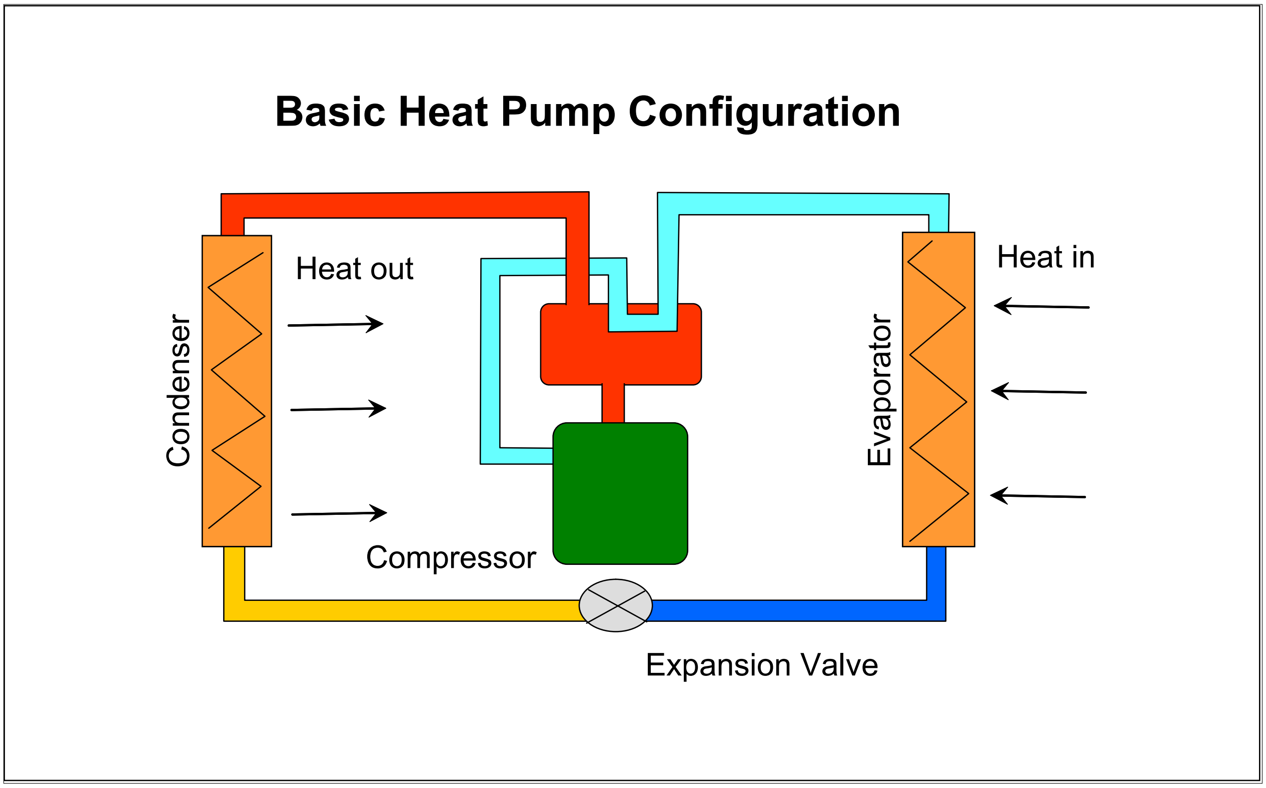
Nome Energy Study

Heat Pumps for Space Heating

AEA Program Manager: David Lockard (771-3062)

Introduction

Heat pumps for space and water heating, while increasingly common in the Lower 48, are often overlooked in Alaska. Most systems are designed to provide space heat in the winter and air conditioning in the summer. Traditionally, they have been installed in moderate climates, often in buildings that would otherwise use electric resistance heating. Now several varieties of heat pumps are available for colder climates and may be suitable for use in Alaska. Ground-source heat pumps differ from traditional geothermal heating; they can be installed across a wide range of geographic locations and ground temperatures. In contrast, traditional geothermal heating is restricted to relatively confined areas with abnormally high temperature gradients, such as near hot springs, and can thus be used to heat indoor spaces without the use of a heat pump. Approximately 50,000 Ground-source heat pumps and over 500,000 total systems are installed in the United States each year.



Heat pumps, while electrically operated, are distinctly different from resistance electrical heaters. Heat pumps are devices that transfer heat from a lower temperature reservoir, usually the ambient environment, to a higher temperature sink. The low temperature reservoir is usually the air, the ground, or a body of water, and it is essentially an unlimited source of heat. This heat, while unlimited, does not come without cost; work in the form of electricity is required to pump it to the high-temperature sink.

Heat pumps work on the same principle as refrigerators and air conditioners. All remove heat from a cold temperature source and pump it to a higher temperature sink. The difference is simply in the desired effect – cooling vs. heating.

A simplified heat pump contains four main parts: a cold source heat exchanger called the evaporator, a compressor, a high-temperature heat exchanger called the condenser, and an expansion valve. This system is filled with a working fluid, such as the refrigerant R-410A. A diagram of this system is shown on the previous page.

In the evaporator, heat is absorbed, vaporizing the refrigerant. This vapor is then compressed, raising its temperature and pressure. The now hot refrigerant vapor is piped to the condenser, where its heat is removed and used for heating. During this heat transfer process, the refrigerant condenses back to a liquid. This liquid then passes through the expansion valve to the low-pressure side of the system, and the cycle repeats.

The effectiveness of a heat pump is called its Coefficient of Performance (COP). The COP is the ratio of heat output to work input. For example, a heat pump operating with a COP of 5 will produce 5 kWh of heat for every 1 kWh of electricity supplied. For this reason, the 'efficiency' of a heat pump is often listed as greater than 100%.

The COP is largely dependent on the temperature difference between the source and sink, and the greater the difference, the lower the COP. For example, a heat pump operating between a ground or air temperature of 45°F and an inside temperature of 70°F has a much higher COP than the same system operating between 0°F and an inside temperature of 70°F. Typical COPs for heat pumps tend to be in the range of 1.5 to 6. This is sometimes described as an efficiency of 150% – 600%.

Heat pumps are classified as either air-source heat pumps or ground-source heat pumps. Air-source heat pumps, as their name implies, extract heat from the ambient air. They are the easier and less expensive type to install. Because the COP is a function of the outdoor air temperature, it will vary widely. This variable COP shows one of the air-source heat pump's main disadvantages in cold climates – peak heating demands coincide with the unit's lowest COP. Heat is therefore most expensive when it is most needed. Nonetheless, there are a number of recent innovations that have led to the development of air-source heat pumps suitable for use down to 0°F.

Ground-source heat pumps have been in use since the late 1940s and use the relatively constant temperature of the earth instead of the outside air for the heat source. This allows the systems to operate with a higher COP in colder weather, making them more appropriate for use in much of Alaska. As with air-source heat pumps, the COP is highest when the difference between the ground temperature and indoor temperature is lowest. Therefore, the colder the ground, the less efficient the system.

There are many configurations for ground-source heat pumps, including an open loop heat pump that pumps water directly from a well or body of water and extracts heat before returning the water back to the same water body or to another one. A dual source heat pump combines an air-source heat pump with a ground-source heat pump.

Heat pumps have been installed in several parts of the state, including the Mat-Su/ Anchorage area, Juneau, and Kodiak. There have also been a few systems installed near Fairbanks, but these were primarily prototype installations and cost savings have not yet been demonstrated.

Ground-source heat pump installations require either horizontal or vertical installation of heat exchanger loops below the ground. This requires significant heavy equipment, which may not be readily available in many parts of the state. For example, a drill rig is needed for vertical installations. In addition, these systems still require electricity to operate and become expensive to operate in areas where the cost of electricity, relative to fuel, is high. They may also be unsuitable for use in areas with permafrost, or where removing heat from the ground might result in permafrost growing or heaving. The combined high installation costs and potentially high operating costs may make these systems inappropriate for rural Alaska; however, they can prove economic in some road-accessible areas of the state.

There are several installers of heat pump systems in Alaska, and local engineering firms can often design a system for a particular application. Expected payback period for an appropriately designed ground-source heat pump is 5–10 years. System life is estimated at 25 years for the in-home components and 50+ years for the ground loop.

System retrofits in areas with oil as the primary heating source and with electrical costs under .13 per kWh have proven to be viable with oil costs above $2 per gallon. Conversion costs range from $25,000 to $30,000 for systems coupled to existing oil boilers with under floor radiant heat distribution already in place. The existing oil boiler acts as supplemental or backup heat for these installations. Systems also come configured for forced-air heating with the air handler built into the unit. There would be no backup heat for this type of installation, since the unit would take the place of the existing oil-fired air handler equipment. Hence, sizing would need to be adequate for the complete heating load of the home, or other backup systems such as electrical resistance heaters would be needed.

In organized cities and service areas permits are required for any heating installation. Lake loops generally require a permit process with several governmental agencies involved, such as the Alaska Departments of Environmental Conservation (DEC), Natural Resources, U.S. Fish and Wildlife, and Army Corps of Engineers.

For open well systems, a less rigorous permitting process is required from DEC. A pilot project is currently in place and conditionally approved for permanent operation. Results from this pilot project and approval will pave the way for open well systems to become routine for the permitting process. Other systems such as closed loop horizontal or vertical installations are more routine and have not been subject to permitting in unorganized areas.

Heat pumps in the right application can cut heating costs. The amount of savings is dependent on the cost of heating fuel, the cost of electricity, and the environment in which the heat pump is installed. Furthermore, a change from combustion based heating (oil, natural gas, propane, coal, or wood) to heat pumps will eliminate combustion appliances and their associated risks, pollution, greenhouse gas emissions, and maintenance.

Because they are electrically operated, a widespread shift toward heat pumps will have consequences for electric utilities; distribution system upgrades may be necessary to accommodate the increased electrical demand. Building owners may also have to update their service entrances to handle the additional electrical load.

One of the primary factors in evaluating a heat pump is the cost of electricity and the need for air conditioning. As a rule of thumb, if the cost of 30 kWh is less than the cost of a gallon of fuel, electric resistance heating may be more economical than oil heat. A heat pump installation may be more economical than oil heat if the cost of 12 kWh is less than the cost of a gallon of fuel.

However, the capital cost of the heat pump is often significantly more than the cost of electric resistance heat or an oil heating system unless air conditioning is required An example can be found in the Pacific Northwest. The hydropower supplied by the dams on the Columbia River has made electricity inexpensive in that region. As a result, much of the residential heating is done electrically, either with heat pumps or with standard resistance heating. A similar situation may occur in areas of the Alaska Railbelt that use oil for heating if, for example, the Susitna Dam is built.

Case Study: Juneau Airport

The Juneau Airport secured funding in October 2008 to install a ground-source heat system. The State of Alaska provided a grant for half of the cost of the project, with the City of Juneau paying for the rest. The system is designed and will be built by Alaska Energy Engineering LLC.

The system involves 215 vertical wells, each 175 feet deep with 0.75 inch high-density polyethylene piping. The heat pumps will supply both heat in the winter and cool air in the summer by using the ground-source heat in a reversible compressor/condenser cycle, with the primary product being winter heat. Alaska Energy Engineering estimates a 260% energy efficiency for the system.

Alaska Energy Engineering has calculated the capital cost of this project at $6.05 million with annual electric use of 656,000 kWh and annual O&M costs of $644,000. This project is being built instead of an alternative fuel oil system. The fuel oil system would have lower capital and annual O&M costs ($5.23 million and $268,000, respectively). The fuel oil system would use 40,825 gallons of fuel and 212,000 kWh of electricity annually. Assuming a fuel oil price of $3.31 and an electric price of 7.9¢ per kWh, the ground-source heat project is expected to save over $85,000 in annual energy costs. Note that the need for air conditioning is an important contributor to the economics of this project.

A similar project is proposed that will produce 4.1 billion BTUs annually to meet approximately 81% of heat load for a new pool in Juneau. It is expected to cost $2 million and to eliminate either 63,200 gallons of fuel oil or 1.5 million kWh annually. Annual O&M costs are estimated at $113,220.

Heat pumps may become more common in Alaska in places that have expensive heating fuels and relatively cheap electricity. They are relatively easy to engineer, design, and install; and they can save energy. A general recommendation on when to install a heat pump over a traditional system is beyond the scope of this document. The decision must be based in part on the available thermal resource, the cost and availability of electricity, the cost of fuel, and capital costs. Specific recommendations will vary by region and are currently done on a case-by-case basis.

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Solar Energy Technologies

AEA Program Manager: Peter Crimp (771-3039)

A solar paneled roof makes efficient use of space and provides a source of power.

TECHNOLOGY SNAPSHOT: SOLAR	
Installed capacity (Worldwide)	Solar heating – 128 GigaWatts Photovoltaic electrical – 7 GigaWatts
Installed Capacity (Alaska)	100s of kW
Resource Distribution	Statewide, best in areas with less precipitation and with southern exposure
Number of communities impacted	Best use is for individual installations where there is no grid power
Technology Readiness	Commercial
Environmental Impact	Minimal, small footprints, no CO_2 emissions
Economic Status	Payback is dependent on fuel oil prices and local resource

Introduction

Energy technologies that use the sun's radiation directly are referred to as solar energy technologies. These technologies may be employed to heat or light living space directly, to supply energy to a heat storage system for later use, or to generate electricity.

Solar energy provides a growing but still small fraction of energy throughout the world. To put solar energy use into perspective, the U.S. Energy Information Agency estimates that worldwide electrical generation from all energy sources for 2005 was 18 trillion kilowatt hours. According to the International Energy Agency, worldwide solar photovoltaic electrical generation was approximately 7.7 billion kilowatt hours in 2006, about 0.05% of total electrical generation. Likewise, heating energy produced by solar, while about 10 times that of solar photovoltaic electric energy production, was also a tiny fraction of total electrical generation.

Direct use of solar energy for heating or lighting is often referred to as passive solar use. The term passive is used because a building employs solar energy by virtue of its design without requiring additional equipment to actively move or store energy. In other words, passive solar systems use the energy of the sun where it falls. A clothesline is a simple example of a passive solar energy device. In this same way designers strive to employ generally conventional materials and building components to advantageously use the sun's energy in buildings. Implementing a passive solar energy strategy involves many decisions, from the location of the building and its overall shape, to the placement of windows and skylights, to the materials to be used inside the structure. In temperate latitudes this functions well. There is a pronounced daily solar cycle. The days are not inordinately short in the winter, and there is a regular cycle of warmer days and cooler nights.

Technologies that use equipment to move or store solar energy from where it is incident to somewhere else are referred to as active solar systems. Examples of these active system technologies are hot water systems where water is heated and the heat is stored in a reservoir, systems where high temperatures are generated to produce steam to generate electricity through conventional steam turbines, or photovoltaic systems where solar energy generates electricity directly in a semiconductor solar cell.

The solar resource in Alaska is significant, but it varies dramatically with the latitude, time of year, and weather. In the northernmost portions of the state, there is abundant sunlight up to 24 hours per day in June, with no sunlight in December. In less extreme northern latitudes, the resource potential is distributed over a greater portion of the year. If solar energy is used for lighting, systems can be optimized for direct sunlight or for diffuse sunlight when skies are overcast, but the strategies differ; it is important to design for the condition that predominates. When solar energy is used for heating or electrical generation, direct sunlight is the most effective form of solar radiation to use. In either case, building systems must be able to operate with or without the solar resource.

Major challenges to using solar energy in Alaska are its seasonal variability and its dependence on weather conditions. In general, the solar resource is most abundant in the summer, when it is least needed. However, there is a reasonable resource available for seven to eight months of the year for all but the most northern areas of the state. Direct heating and daylighting with the sun require minimal technology, but they rely on good building design to prevent overloading in the summer months and to promote energy gathering during the shorter days closer to the winter season.

Two major factors should be considered when employing solar energy in Alaska: the abundance of sunlight when the energy is needed and the cost of other forms of energy. Technologies other than solar must carry the load during the dark times of the year in Alaska. For this reason, the addition of a solar auxiliary system will not reduce the capital cost of a primary heating or electrical system. Primary systems must be designed to operate for months without benefit of significant solar input.

Active systems hold the most promise for Alaskan applications. These are systems that can store energy for longer periods of time or be incorporated as auxiliary energy sources into existing energy systems. Active systems also lend themselves to being controlled automatically. Because of the seasonal nature of the solar resource in Alaska, passive solar designs yield only modest benefits, since they cannot store solar energy for an extended period of time. Passive solar lighting systems use sunlight only during the daylight hours. Passive heat systems are generally effective for some hours (in some cases a few days) after collecting solar energy, and they often require active participation in the building operation.

Active solar systems most suitable for Alaska are photovoltaic systems and solar hot water systems. Except for specific niche applications, it is unlikely that photovoltaic electrical generation is suitable for reducing the cost of electricity in Alaska. Grid-connected photovoltaic systems offer the most economical means of generating electricity with sunlight. At current prices an installed, grid-connected system in Interior Alaska could produce electricity for approximately $1.50 per kilowatt hour. Connection to an electrical grid enables a photovoltaic system to avoid expensive electrical storage.

The cost of solar-generated electricity in remote areas with no electrical grid available would be significantly higher due to the cost of additional batteries and inverters. There have been only two Alaskan villages with average electrical kilowatt hour costs over $1 per kilowatt hour for the past five years. Lime Village, which has an installed photovoltaic system, has electrical costs of $1.26 per kilowatt hour. Stony River pays $1.01 per kilowatt hour.

Solar hot water systems offer more promise in Alaska than photovoltaic electrical generation does, although the present installed cost of systems is still expensive. Solar hot water systems suitable for Alaska can provide hot water for space heat or for domestic use. The low density of the Alaskan solar resource precludes the economical use of high temperature solar technologies, such as systems that generate steam to produce electricity. As an example of the difference between the cost of solar hot water and hot water from fuel oil, consider a household-sized solar hot water system with an energy cost spread over twenty years. The cost of the solar energy would be approximately $100 per million Btu. The cost of that same energy from fuel oil, if the fuel price were $6 per gallon, would be about $40. There might be some rural villages where solar could be an economical component of an energy system. On the road system, where fuel oil is less expensive, some might wish to use solar hot water for reasons other than fuel oil price alone.

Conclusions

Solar holds little promise to economically reduce Alaska's dependence on fossil energy. Prices for solar electric systems and solar hot water systems make them more expensive than conventional fuel technologies. Although the fuel is free for solar technologies, the capital cost is not. It is conceivable that innovative design for specific applications could reduce the capital cost of a system. Then the solar hot water system might be able to economically offset fuel oil use. Solar hot water systems have many components that are used in conventional fuel systems, and the capital cost of the solar systems is a combination of the costs of these numerous components. On the other hand, the cost of a photovoltaic system resides primarily in photovoltaic panels themselves, and this cost is determined by the worldwide market. It is unlikely that innovations in end-use design will significantly change the capital costs of solar electric installations.

In Alaska, the best candidates for solar use would be sites off of the road system that operate only in the summer months.

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Web-based

The website http://www.alaskasun.org/ has excellent information, including a number of publications related to solar installations in Alaska, and a list of contractors and suppliers.

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Alaska Coal Energy Resources

AEA Program Manager: Mike Harper (771-3025)

The coal powered heat plant at UAF as seen during Winter Solstice.

TECHNOLOGY SNAPSHOT: COAL	
Coal Resources (Worldwide)	Recoverable coal is approximately 998 billion short tons (2004 numbers)
Coal Resources (National)	Approximately 491 billion short tons of demonstrated reserves, estimated 275 billion tons recoverable (2007 numbers)
Coal Resources (Alaska)	170 billion short tons identified resources; approximately 5.6 trillion short tons of hypothetical coal resources
Resource Distribution (Alaska)	Distributed in eight major coal provinces and numerous smaller coal fields and occurrences
Number of communities with potential coal resources	Over 40
Technology Readiness	Proven technology for electrical power generation and space heating
Environmental Impact	Surface mining requires reclamation. Combustion for electrical power generation must meet EPA requirements
Economic Status	Economically mined in Interior Alaska (Healy) for power generation and some space heating, active coal exploration in Western Arctic, Cook Inlet and Alaska Peninsula

Coal is a brownish-black to black combustible organic sedimentary rock formed by the decomposition of plant material, most often in a swampy or boggy environment. This organic material or peat is buried, compacted, and hardened over millions of years. This process is called coalification. During coalification, peat undergoes several changes as a result of bacterial decay, compaction, heat, and time. Peat deposits vary and contain everything from pristine plant parts like roots, bark, spores, etc. to decayed plants. In coalification, peat passes through four main phases of coal development: lignite, sub-bituminous coal, bituminous coal, and anthracite. These end products are composed primarily of carbon, hydrogen, oxygen, and some sulfur along with water moisture and non-combustible ash. The amount of carbon and volatiles (water and gas) as well as the amount of energy content of the coal determine its rank. The amount of energy in coal is expressed in British thermal units (Btu) per pound. The higher the rank, the greater the heating value.

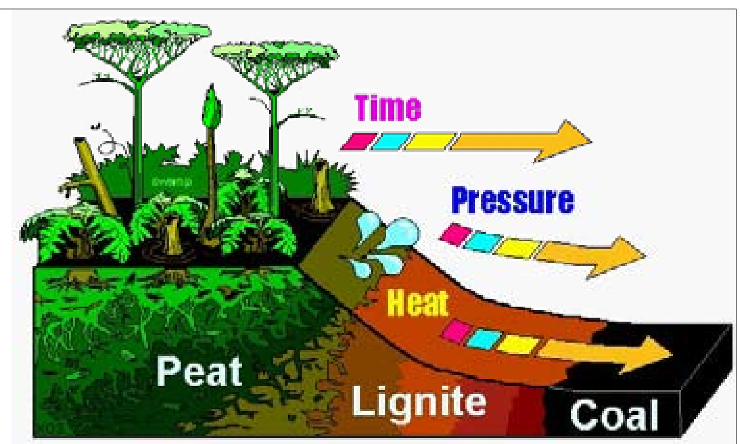
Based on reliability of data, coal resources are classified into four classes that depend on standard-distances-from-points-of-thickness measurements. These are (1) measured, (2) indicated, (3) inferred, and (4) hypothetical. These four classes of coal resources are based on degree of geologic assurance that the rank and quantity of a coal seam (or seams) have been estimated from high (measured) to lowest (hypothetical). Identified coal resources include measured, indicated, and inferred coal resources.

Summary of Total Alaskan Coal Resources

Resource Category	**Total Resources (in millions of short tons)**
Measured resources	6,500
Identified resources	170,000
Hypothetical resources	5,600,000

In general, hypothetical resources are located within broad areas of known coal fields where points of observation are absent and evidence is from distant outcrops, drill holes, or wells, and where coal may reasonably be expected to exist in known mining districts under known geologic conditions. Additionally, the classification of coal resources is based on the mineable thickness of the coal seam.

The United States is estimated to contain 30% of the world's coal resources. Alaska is believed to hold about half of that. Most coal resources in Alaska are in the hypothetical resource class because they have been poorly studied, there are few data points of measurement, and there has been little or no drilling to substantiate resource estimates. Identified resources are about 170 billion short tons; however, coal-bearing strata underlie about 9% of Alaska's land. The state's total hypothetical resources of coal are estimated to exceed 5.6 trillion tons.



Source: Kentucky Geological Survey, http://www.uky.edu/KGS/coal/coalform.htm

The major coal provinces in Alaska are Northern Alaska, the Nenana area, the Cook Inlet-Matanuska Valley, the Alaska Peninsula, and in the Gulf of Alaska and the Bering River. Potentially significant identified coal resources are present in other coalfields on the Seward Peninsula, Yukon-Koyukuk, and Upper Yukon provinces. Numerous smaller coal basins and minor coal occurrences are distributed from southeast Alaska to the interior parts of the state. With a few exceptions, most Alaska coal is low in sulfur, in many cases containing less than 0.5%. Alaska coals also exhibit low metallic trace elements, good ash-fusion characteristics, and low nitrogen content making them favorable for meeting environmental constraints on combustion in power plants.

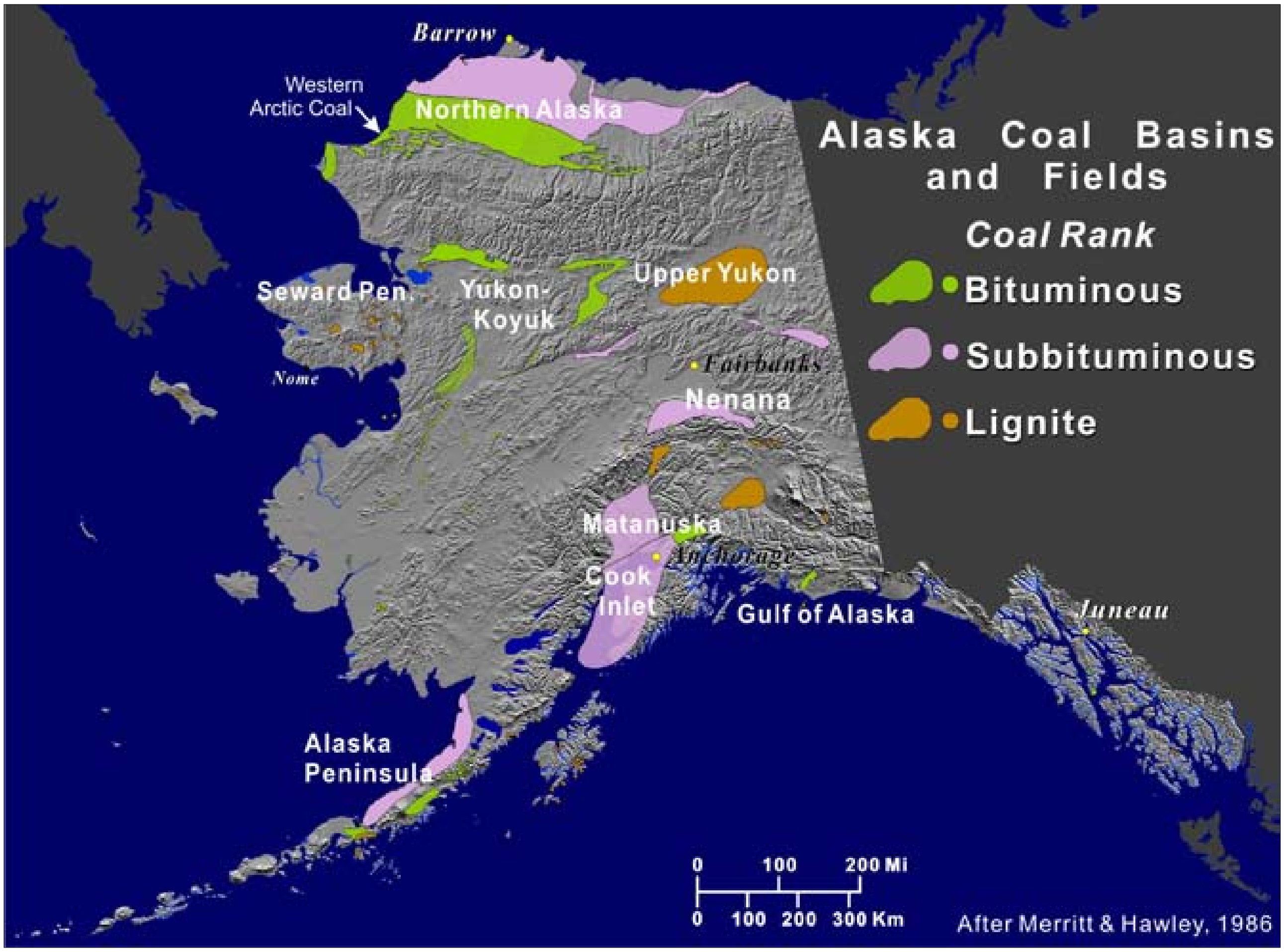
Alaska's coal is dominantly bituminous of Cretaceous age, or sub-bituminous of Cretaceous and Tertiary age. Except for Mississippian coal of the westernmost Northern Alaska Province, Alaska coal resources formed in widespread deltaic and continental depositional systems during Cretaceous and Tertiary time. The younger Tertiary age coals formed within sedimentary basins are related to fault systems with complex gravity and strike-slip motions that controlled basin formation and influenced deposition by differential settling.

Components and Heating Value of Coal by Rank

% weight	Anthracite	Bituminous	Sub-Bituminous	Lignite
Heat Content (Btu/lb)	13,000-15,000	11,000-15,000	8,500-13,000	4,000-8,300
Moisture	< 15%	2 - 15%	10 - 45%	30 - 60%
Fixed Carbon	85 - 98%	45 - 85%	35 - 45%	25 - 35%
Ash	10 - 20%	3 - 12%	≤ 10%	10 - 50%
Sulfur	0.6 - 0.8%	0.7 – 4.0%	< 2%	0.4 – 1.0%

Right: A residential coal-fed boiler in Healy.

Identified Alaska Coal Resources by Province		
Province/Coal Field	**Millions of short tons**	**Coal Rank**
Northern Alaska province		
		High-volatile bituminous & sub-bituminous; extensive lignite and minor anthracite
	150,000	(Identified resources.)
	~3,600,000	(Hypothetical resources)
Cook Inlet-Matanuska Province		
Beluga and Yentna fields	10,000	Sub-bituminous
Kenai field (onshore only)	320	Sub-bituminous
Matanuska field	150	High-volatile bituminous to anthracite
Broad Pass field	50	Lignite
Susitna field	110	Sub-bituminous
Nenana Province		
Nenana basin proper	7,000	Sub-bituminous
Little Tonzona field	1,500	Sub-bituminous
Jarvis Creek field	75	Sub-bituminous
Alaska Peninsula Province		
Chignik and Herendeen Bay fields,		
Unga I.	430	High-volatile bituminous
Gulf of Alaska Province		
Bering River field	160	Low-volatile bituminous to anthracite
Yukon-Koyukuk Province		
Tramway Bar field	15	High-volatile bituminous
Upper Yukon Province		
Eagle field	10	Sub-bituminous and lignite
Seward Peninsula Province		
Chicago Creek field	4.7	Lignite


Barrow
Western
Arctic Coal
Northern Alaska
Alaska Coal Basins
and Fields
Coal Rank
Bituminous
Subbituminous
Lignite
Seward Pen.
Yukon-
Koyuk
Upper Yukon
Nome
Fairbanks
Nenana
Matanuska
Anchorage
Cook
Inlet
Gulf of Alaska
Juneau
Alaska
Peninsula
0 100 200 Mi
0 100 200 300 Km
After Merritt & Hawley, 1986

Historical and Current Production and Exploration

Coal was officially discovered in Alaska in 1786, with the first documented production in 1855. Small-scale mining is recorded at numerous sites throughout the state, with local mines being developed to fuel river steamboats, placer gold mines, and canneries before 1900. Significant production began in 1917 after extension of the Alaska Railroad into the Matanuska coalfield, and by 1968, more than 7 million short tons of bituminous coal had been mined from the Matanuska coalfield, most of it for electrical power generation. Significant mining in the Matanuska field ceased in 1968, when Cook Inlet natural gas replaced coal for electrical power generation in the Anchorage area.

Since the end of World War I, coal has been mined continuously in the Healy coalfield, which is within the Nenana coal province. Alaska's only operational coal mine today, the Usibelli Coal Mine, produces sub-bituminous coal from its Two Bull Ridge mine site near Healy, with an output of 1.357 million short tons of coal in 2007. Usibelli shipped over 308,146 short tons of coal to Chile and supplied six power plants in interior Alaska with approximately 900,000 short tons of coal.

In 2007, BHP Billiton Ltd. drilled nine holes in the western Arctic coalfields on land owned by Arctic Slope Regional Corporation. The purpose was to test the thickness of the coal seams and evaluate the quality of the coal in the historic Kuchiak Mine area, first tested in 1994. Exploration continued in 2008, and BHP also began environmental baseline studies and initiated cleanup activities at the Kuchiak Mine.

PacRim Coal LP has also been active with continued environmental, permitting, and engineering work on the Chuitna Coal project west of Anchorage, on the north side of Cook Inlet. The project is being designed to mine 3 to 12 million short tons of coal per year from proven reserves of over 770 million short tons.

Conclusions

Alaska has vast resources of high quality, low sulfur coal that has great potential for providing energy locally and for export. Technology exists for extracting coal and for generating both electricity and space heating from it. The economics of coal mining through electrical power generation and space heating are well known for a given resource base. These economic models can be extrapolated for the economy-of-scale necessary for rural settings. Mine-mouth electrical power plants can greatly reduce the need to transport large volumes of coal, and electrons can be transmitted to a number of communities via power lines rather than by hauling coal over great distances. Because there is a lack of detailed information on bed thickness and lateral extent of coal seams in many of Alaska's coal provinces, the total volume of identified coal resources suitable for mining remains much lower than what is likely present.

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A coal seam shows through an eroded bank near Healy.

Natural Gas

DNR Program Manager; Robert Swenson, 451-5001

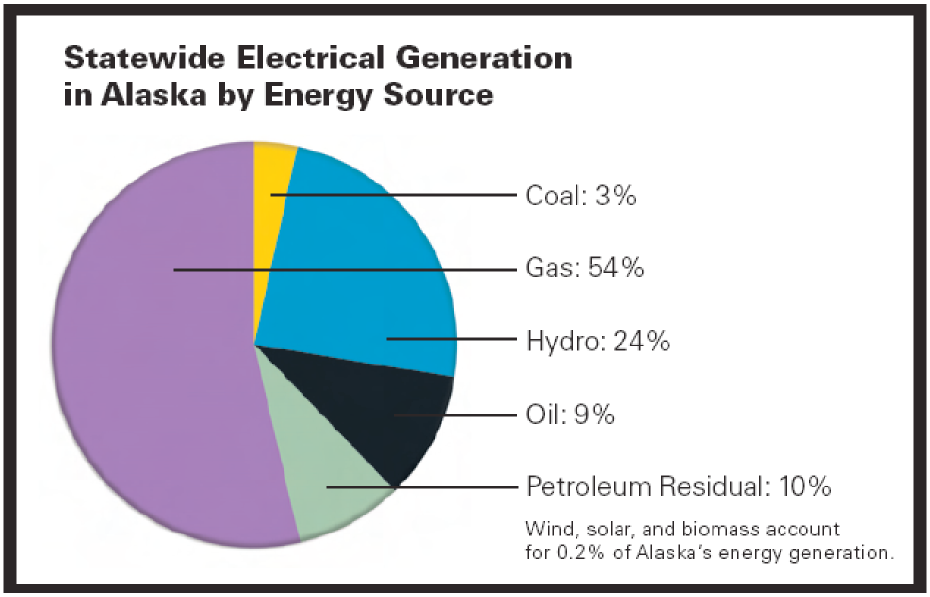
TECHNOLOGY SNAPSHOT: NATURAL GAS	
Current Production (US)	Over 25 trillion cubic feet annually
Current Production in Alaska	North Slope and Cook Inlet, 454 billon cubic feet
Resource Distribution	North Slope and Cook Inlet Some exploration potential in other Basins
Number of Communities Impacted	Railbelt and North slope
Technology Readiness	Proven exploration and production technology readily available.
Environmental Impact	Cleanest burning non-renewable. Exploration activity, production facilities, and pipelines must not adversely affect land and water resources.
Economic Status	Currently economic in Anchorage region and minor railbelt

The term 'natural gas' refers to a common and widespread product of organic decomposition and it is found in varying quantities in nearly every part of the planet. Natural Gas is produced in nature by two distinct methods: (1) organic material is broken down by bacterial decomposition with the by-product of methane (such as in peat bogs, land fills, or the digestive system of cattle), or (2) thermal decomposition where the by-product is both gas and liquids (such as coal or organic- rich sediments being heated up deep within the earth to produce methane, propane, other heavy gases, and oil).

The key challenge for using natural gas as an energy source is our ability to economically collect it in sufficient quantities so that it can be used for heat and power. Unfortunately, the very common bubbles seen in lakes and bogs cannot supply enough fuel for sustained energy production, so it is necessary to find and tap into a place where nature has accumulated it over hundreds of thousands of years by a natural trapping mechanism. The most common forms of natural accumulation are: (1) conventional gas reservoirs in porous rock deep within the earth, (2) thick underground coal seams where the gas is both trapped and adsorbed to the organic material (coal bed methane), and (3) a newly emerging potential natural gas source, hydrates, where the gas molecule under certain pressure and temperature conditions is surrounded and trapped by a crystalline structure of ice.

Natural gas accumulations are a common source of clean burning energy throughout the world. Natural gas is used and transported in many forms including conventional pipeline distribution of gaseous form, pressurized vessels of liquid propane (LP), and liquefied natural gas (LNG) as a supercooled liquid in unpressurized insulated containers. In the United States natural gas provides nearly 21 percent of the energy supply, and the US Department of Energy (USDOE) forecasts that this consumption level will climb slowly over the next decade, and then start decreasing through the year 2030 (see figure 2). The USDOE also reports that natural gas will be the energy source for 900 of the next 1000 new power plants being developed in the U.S.

In Alaska, natural gas is used to generate 54% of the electricity being consumed by industry and the public. Figure 3 compares the amount of gas being consumed annually in the Anchorage area for residential use and power generation. Clearly, natural gas makes up an important part of the overall energy portfolio of Alaska and will for the foreseeable future. The dominant impediment to increased use of natural gas in other parts of Alaska is the significant cost of exploration and development, or of transportation from areas of large known accumulations to areas where it can be utilized for heat and power by a smaller population base.



From Alaska Energy Authority, Energy Atlas

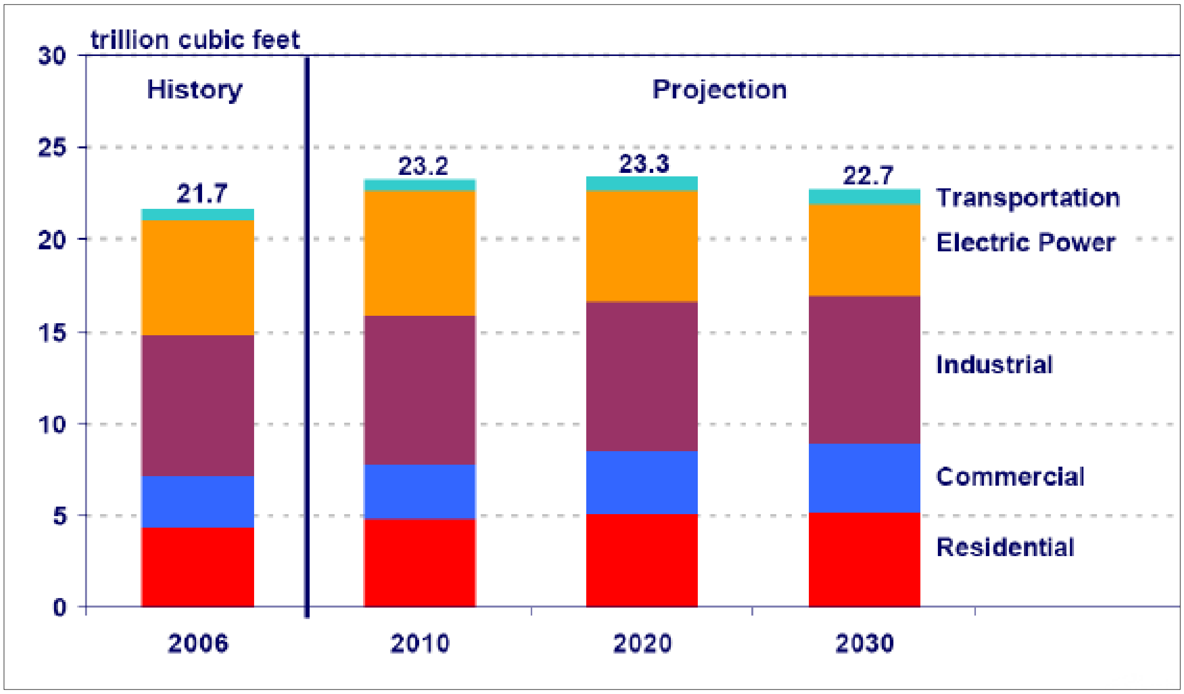


Figure 2: Total US consumption and projections of Natural Gas use by sector in Trillions of cubic feet. From the US Department of Energy

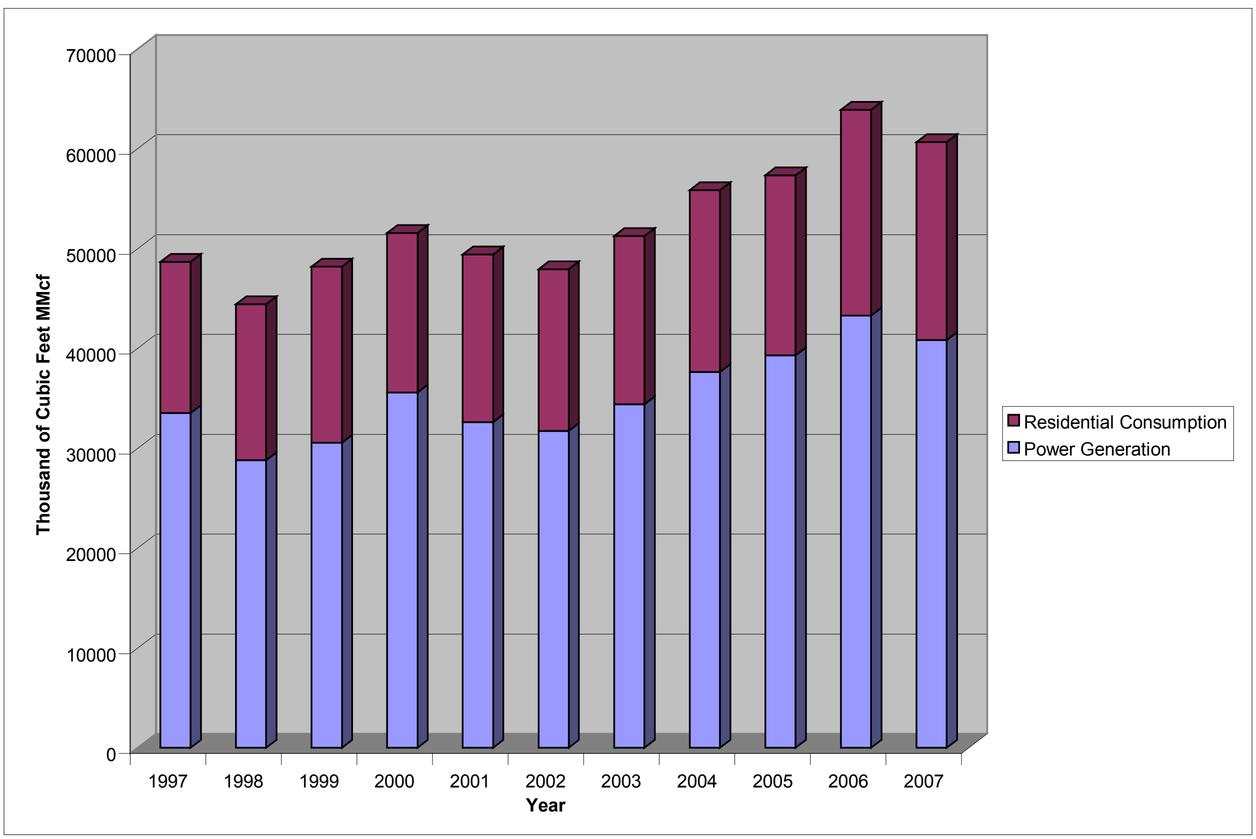
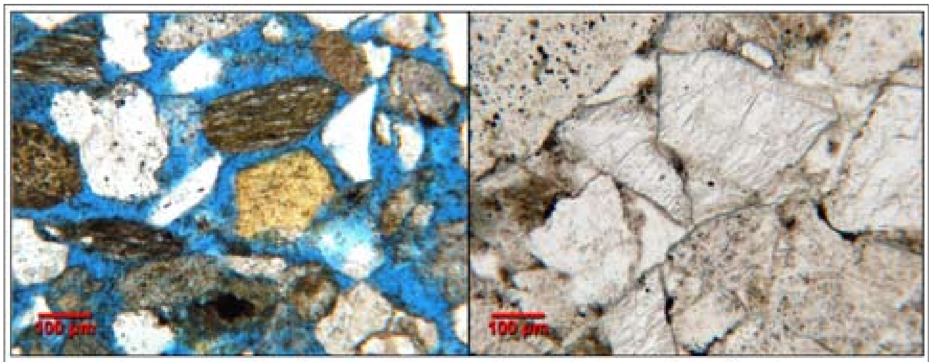


Figure 3: Graph showing consumption of Natural Gas in Alaska for residential and electricity production for the decade 1997-2007. Data from US Department of Energy.

The dominant molecule in most natural gas accumulations is methane, but in many cases there are also minor amounts of other hydrocarbons such as propane, ethane, and butane. Thermally derived natural gas comes from sedimentary rocks that contain elevated levels of organic molecules rich in hydrogen and carbon atoms referred to as source rocks. The presence of the right kind of source rock in a sedimentary basin that has been subjected to the right conditions of burial and increased temperature may generate a natural gas accumulation, however many complimentary conditions must be met. To understand the requirements for an accumulation of natural gas (and oil), geologists use the petroleum system concept where a functioning petroleum system must include the following five elements: 1) source rock, 2) migration pathway, 3) reservoir rock, 4) seal rock, and 5) trap.



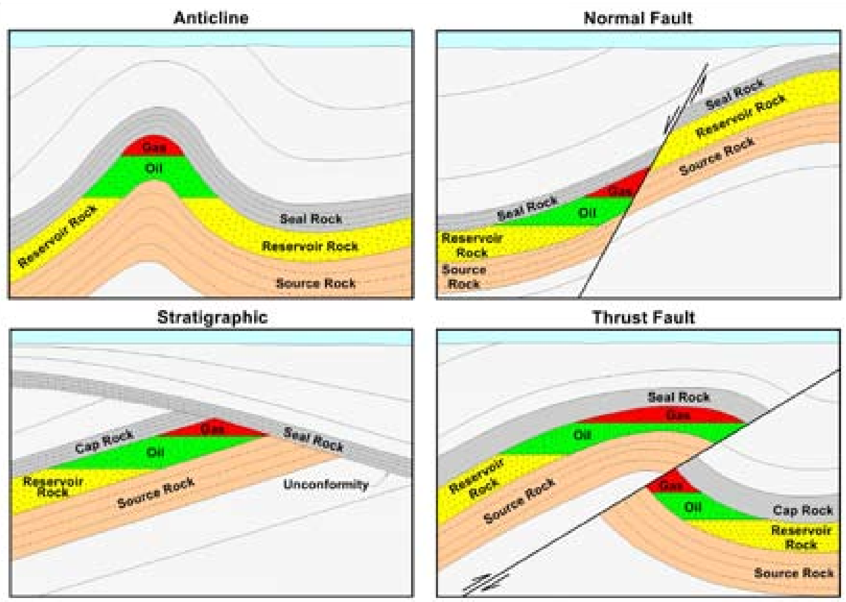
Microscopic view showing a high-quality reservoir sandstone on the left and a non-reservoir sandstone on the right, both from the Alaska Peninsula-Bristol Bay region. The high-quality sandstone from the Bear Lake Formation includes abundant interconnected pores (blue areas) capable of storing hydrocarbons and allowing them to flow to producing wells. The non-reservoir sandstone from the Naknek Formation consists of tightly-fitted sand grains (g) and cement-filled pores (c), has essentially no porosity and permeability.

When source rocks are slowly heated to the right temperature (between approximately 150°F and 250°F) organic molecules react to form the mix of chainlike hydrocarbons we call crude oil. Source rocks heated to temperatures within this range, the 'oil window,' are said to be thermally mature for liquid hydrocarbons, but they commonly also begin generating natural gas in addition to oil. Source rocks capable of generating oil are referred to as oil-prone and are typically derived from marine algae and other microorganisms. When source rocks are heated above 250°F they are described as overmature for oil, but can still generate significant quantities of natural gas. Source rocks that start out rich in carbon but leaner in hydrogen (coal, some shale, and limestone) can generate natural gas, but not the more hydrogen-rich liquid hydrocarbons found in crude oil. These types of source rocks are referred to as gas-prone and typically consist of organic material derived from land vegetation. These transformations occur due the rise in temperature with increasing depth below ground surface; geothermal heat. The rate at which the temperature increases with depth is described by the geothermal gradient which, on average in drilled sedimentary basins of the world, is about 50°F per 1,000 feet of depth. This means that the deeper we go beneath the earth's surface, the warmer the rocks become. The part of a sedimentary basin where source rocks are buried deep enough for temperatures to be high enough to cause these thermal conversions is informally referred to as the "petroleum kitchen".

When hydrocarbons are generated in the kitchen, their buoyancy quickly drives them to migrate out of the source rock following the path of least resistance through the most permeable strata they encounter. This migration out of the source rock creates the possibility of trapping and accumulation in a reservoir rock.

Reservoir rocks are porous and permeable formations that can store oil and gas in pore spaces between grains and later allow them to flow out of the rocks to wellbores, where they can be extracted. Sandstones, limestones, and dolomites, under the right conditions, can possess enough interconnected pores to form good reservoir rocks. Some low permeability rocks can still function as reservoirs for natural gas, due to the lower density and greater buoyancy of gas. In order for the pores in a reservoir rock to become filled with gas (or oil, if present), it must be located along a hydrocarbon migration pathway. If a pathway does not lead to a reservoir rock, the hydrocarbons may be lost to the surface environment.

Only where porous and permeable rocks are enclosed in trapping geometries does gas (and oil, if present) stop migrating and accumulate in the reservoir rock to form fields. Effective traps consist of reservoir rocks overlain and/or laterally bounded by impermeable seal rock, and are of two basic types. Structural traps occur where rock layers are deformed by folding or faulting to form concave-downward shapes capable of containing buoyant fluids such as gas. Stratigraphic traps occur where porous, permeable reservoir rocks are encased in impermeable seal rocks as a result of non-uniform deposition of sediments.



Simplified cartoons showing some common types of hydrocarbon traps recognized in producing oil and gas fields around the world.

For example, clean sands on a wave-worked beach may grade laterally into a muddy offshore setting, and with time, the muddy offshore zone may migrate over the older beach sand, setting up a possible future stratigraphic trap, consisting of a wedge of porous reservoir sands between the impermeable muds above and below. Structural traps are usually much easier to identify and generally host the initial oil and gas discoveries in a basin. Stratigraphic traps are much harder to target, and their successful prediction normally requires more detailed mapping of the subsurface geology. This is best achieved by interpreting high-quality, closely spaced seismic data along with information gained from previously drilled surrounding wells. In any case, in order for traps to host gas fields (or oil), they must be created prior to hydrocarbon generation, expulsion, and migration from the kitchen. Moreover, they must then remain intact, uncompromised by later folding, faulting, or excessive burial.

Coal constitutes a special type of gas-prone source rock that can generate gas either as a result of the thermal maturation described above, or through microbial degradation at shallower depths in the absence of oxygen. Gas generated through the latter process is referred to as biogenic gas. In buried coal seams, biogenic gas molecules are typically dissolved in the surrounding pore waters and stored in the coal matrix, where methane molecules attach to coal particles. As long as the coal remains buried at this same depth, it is subjected to the pressure of the overlying rock and groundwater (hydrostatic pressure) and the methane molecules cannot form bubbles that can migrate out of the coal. If the coal seam is subsequently uplifted to shallower depths in the basin, the hydrostatic pressure is reduced, allowing the methane to bubble out of solution and migrate out of the coal seam. Once this migration starts, the gas follows the path of least resistance, as noted above, and will either migrate to a reservoir in a trapping configuration, get stranded in small quantities in the subsurface, or will eventually migrate to the surface and be lost to the atmosphere.

Alaska is endowed with enormous proven natural gas resources. These known resources reside exclusively on the North Slope and in Cook Inlet basin. Outside of these two regions, the presence of natural gas existing in large subsurface traps is unknown. However, several of the non-producing sedimentary basins include geologic characteristics that suggest natural gas accumulations could be present. These include the Copper River, Kandik, Nenana, Yukon Flats, and the North Aleutian basin. These basins are known to include organic-rich rocks that could be source rocks for natural gas if buried to depths within the kitchen where thermal transformation can generate hydrocarbons. The onshore portion of the Hope basin includes known coal reserves in the vicinity of Chicago Creek, southeast of Kotzebue. Coal in this area is lignitic and submature for thermogenic gas, but under the right subsurface conditions could generate biogenic methane. It is not known if the requisite conditions for biogenic gas generation have been met in the Chicago Creek area. Other basins have been recognized around the state, including the Minchumina, Holitna, and Selawik basins, but their gas potential is uncertain owing to insufficient high-quality surface and subsurface data.

Map showing major sedimentary basins in Alaska. Multiple petroleum system are established oil and gas producers in the North Slope (1) and Cook Inlet (2) regions. The Alaska Peninsula (3) and Gulf of Alaska regions are known to possess all of the elements of petroleum systems, but they remain underexplored and unproven. Most of the basins in Interior Alaska (5) are challenged by a variety of issues, thought all appear to possess some reservoir-quality sandstones.

Alaska has many sedimentary basins that are known to include elements required for functioning petroleum systems. To have a functioning petroleum system, a basin must include a source rock, migration pathway, reservoir rock, seal rock, and an effective trap for gas. Detailed geologic information is lacking from all of these basins that would allow realistic evaluation of whether petroleum systems are present.

Exploring for natural gas in Alaska's non-commercial basins will require modern, high-quality surface and subsurface data. The normal exploration progression includes conducting detailed surface bedrock geologic mapping, acquiring reflection seismic surveys, and finally, probing the most promising areas by drilling wells evaluated with modern wireline geophysical log suites. Each stage of this cycle is typically more expensive than the preceding step, with costs associated with a remote exploration program ranging from 40 to 100 million dollars. Currently, legacy datasets from previous exploration cycles are available only for limited portions of the Copper River, Middle Tanana, and Yukon Flats-Kandik basins. Developing a significant natural gas discovery in one of Alaska's non-producing basins could be very expensive unless the accumulation was located at a shallow depth and close to both the point of use (a rural community or group of communities) and transportation infrastructure. Natural gas discoveries that do not meet the industry's commercial economic metrics due to size, gas production rate, location, development costs, or other factors, would need to be evaluated for possible governmental subsidy, or remain undeveloped.

Summary

Natural Gas is a clean burning energy alternative that enjoys widespread use around the world. Natural gas is the primary energy source for many Alaska residents, but because of transportation difficulty and cost, its use is restricted to the areas that contain identified fields found during industrial-scale exploration in the 1960s. The inherent economic risk and high cost of exploration has limited the amount of activity in many of the remote sedimentary basins in the state. Nevertheless, there are other areas that contain significant potential and the most economically feasible method of exploring for natural gas in those areas is to facilitate industrial scale exploration. The State of Alaska has a number of programs and incentives that encourage exploration in these areas, but the economies of scale has limited the amount of activity. The Alaska Department of Natural Resources, and the Alaska Energy Authority are committed to finding ways to facilitate that activity, and to provide as diverse a set of energy options for the citizens as possible.

Energy Delivery

Transmission Lines

Transmission lines are used to deliver electrical energy from generation source to end-use location. The electrical energy travels along wires in overhead lines strung between towers or poles or in underground lines insulated from the earth. The voltage of the transmission line usually depends on the distance and the amount of energy being conducted.

Transmission lines can be deployed for several uses:
1) To deliver electrical energy to a distant location to increase coverage and reduce the overall cost of delivered energy. AVEC is developing a micro-grid system that allows for consolidation of generation. This consolidation can provide reduced overall costs through delivery of the single generator over a transmission line to a neighboring community. The communities of Toksook Bay, Tununak, and Nightmute are interconnected through the use of micro-grids.

2) To deliver excess energy to an area that can utilize it. An example is the Swan – Tyee transmission line, now under construction, that will deliver power from the Tyee Hydroelectric project for use in Ketchikan.

3) To reduce losses. If a single transmission line is delivering power between two points, adding another transmission line between those points, adding a second line in parallel, will reduce the overall transmission line losses. The Northern Intertie from Healy to Fairbanks is an example a second line in parallel (with an existing line constructed in the 1960s).

4) To increase reliability. Operating two lines in parallel allows for one line to disconnect from service while the remaining line continues to deliver power.

5) Routing a transmission line to interconnect a new resource. Routing a transmission line by a location that can produce energy will allow the energy to be delivered in either direction along that transmission line. If a transmission line in the planning stage is rerouted by a geothermal site, when the site is developed, the geothermal energy can be delivered to either end of the transmission line for use in the system.

Transmission lines can range in cost from $100,000/mile to $2,000,000/mile depending on the voltage, wire size, terrain, icing conditions, accessibility, and structure type. Lower voltage systems of 15,000 – 25,000 volts can run from $100,000/mile to $400,000/mile. Higher voltage systems of 69,000 – 230,000 volts can cost $300,000/mile to $2,000,000/mile.

In recent years, the use of Direct Current (DC) transmission lines to transmit electricity has increased. There are several trade-offs when using DC rather than traditional AC electric transmission. Inverter stations are required at each terminal to convert DC to AC, and that energy can be run through a transformer to increase or decrease voltage. The cost savings for reduced transmission line facilities may be masked by the increased cost of inverter stations and harmonic reduction. The Battery Energy Storage System described in the Storage Technology section uses similar converter technology to convert the 5,000-volt DC source from the batteries to 13,800 volts AC which can be interconnected with the existing transmission system. DC systems are usually reserved for long transmission lines that deliver large amounts of power. ABB has a commercial HVDC system called HVDC Lite. It is for systems under 100,000 kilowatts of energy transfer, and typically used to reduce dynamic voltage and power swings to which AC power systems are susceptible. Converters on the receiving end must be force-commutated to provide the constant 60-hertz or cycles per second that are required of standard AC systems.
DC systems are significantly complex and should not casually be applied to the distribution of electricity.

Pipelines

Pipelines can be used to deliver liquid and gaseous energy products such as steam, hot water, crude oil, natural gas, petroleum liquids, and hydrogen. Steam can be transferred over distances of approximately one mile, using the steam pressure as the motive force for delivery. For other product pipelines, compressor stations or pump stations are required. Long pipelines typically require large transfer volumes to share the fixed costs to be economical. Short, hot water pipelines can be economical if there is adequate thermal insulation to reduce thermal heat loss from the pipe system. Small area, neighborhood, hot water delivery can be economic and can be viewed as an extension of the hydronic heat delivery systems used in homes today. Any hot water heat delivery systems that extend outside the heating envelope must be protected from freezing through the application of antifreeze fluids.

Piping systems range in size from small residential systems that distribute hot water in a residence(¾ inch to 1 inch piping), to neighborhood or district hot water systems(2 inch to 6 inch range), to large industrial facilities that can deliver steam, natural gas or crude oil). The largest pipeline in the state is the 42-inch Trans Alaska Pipeline System which delivers 800,000 barrels of crude oil daily from Prudhoe to Valdez.

Power lines in Beaver deliver electricity to residential locations throughout the remote village.

Pipeline travels under the Colville River.

Golden Valley Electric Utility installed a Ni-Cad battery that has prevented over 256 power outages.

Energy Storage

AEA Program Manager: Peter Crimp (771-3039)

A battery system is an uninterruptible power supply.

Introduction

Renewable resources such as wind, solar, and hydro are abundant at some times and in some places, but they are not always available when and where they are needed. Other energy sources may be required to allow these renewable resources to be drawn upon at a later time when needed, or to switch to another generation source when renewables become unavailable. Alternatives can take the form of storage or dispatchable generation technology that can be used when required.

The use of energy storage is considered by many as an essential component of future utility delivery infrastructure throughout the United States. Energy storage can be used in a wide range of applications to improve availability and reliability of delivered power, to support variable distributed generation (including renewables), to stabilize transmission and distribution lines, or to time shift consumption through bulk storage to achieve the most efficient use of baseload generation. Many of these applications require short bursts of power to balance and control energy, with discharge times ranging from milliseconds to a few minutes.

Storage can be classified by several key parameters:

- Rated Power (kW) The rated power output available from the device under normal operating conditions.
- Rated Capacity (kWh) The total amount of available energy within the storage system.
- Response time (Hz) The speed at which the storage device can respond to changes in the power system.

System configuration and design philosophy will largely determine the incorporation of storage. Storage time can range anywhere from a long-term seasonal or annual basis, down to an hourly or even shorter basis.

It should also be noted that in most cases storage is not an end in itself, but a bridge used as required to insure power quality or to simplify control. In most applications, storage is used to bridge a low-cost energy option like hydro or wind, to a higher-cost energy option like natural gas or diesel, allowing a seamless switch between the two. Long-term storage is typically not economical. When compared, the capital and maintenance costs of storage technology are well above the cost of providing power with conventional dispatchable generation.

In some instances a case can be made for storage on an expanded basis, where excess renewable energy is stored for use at a later time, but this happens most often in locations with very high costs for marginal power or in places where natural storage options are readily available.

Many strategies can be used for energy storage, including chemical storage (hydrogen or biofuels – see section on alternative fuels), electrochemical (batteries, fuel cells, and capacitors), electrical (capacitors), mechanical (flywheels or pumped hydro), or thermal storage. The appropriate choice is made based on location, geography, accessibility, climate, and local resources. All electrical storage systems add flexibility to the electric grid, increasing the options available for grid optimization and management. Which storage technology would perform best depends on local economics, the proposed application, and details of the site.

Conventional Hydro

The simplest form of energy storage is seen in conventional, large-scale hydro, where dams create large reservoirs that capture maximum runoff in the spring and release it over the year to provide energy the following winter. This can be compared to run-of-the-river hydrokinetic systems, where energy can be extracted only from the river as it runs. Power is lowest when the river is lowest, which in Alaska is in the winter when power demand is highest. However, conventional hydro systems are costly and can be built only where geography and markets coincide. For larger applications, reservoir hydro projects can be combined with other large renewable power to allow optimal dispatching of renewable applications.

Pumped Hydro

While conventional hydro simply uses flowing water as it is available, pumped hydro uses excess electrical power to move water from a lower elevation to a higher one. It then runs the water back through a turbine to generate power during times of increased demand. Usually these cycles occur on the time scale of a day or week. When power demand is low, typically at night, water is pumped into the reservoir. During the day, when power needs are generally high, water is released to generate power. In this way pumped hydro can be used to convert undispatchable renewable power into dispatchable power.

Bradley Lake Hydroelectric Dam provides energy to residents from the Kenai Peninsula to Fairbanks.

Where a suitable location can be found and large storage capacity is required, a pumped storage system is the most cost-effective form of storage available. The right geographical location has adequate water, a moderate climate, and enough variation between times of low-cost power and high-cost power. Most pumped hydro facilities have been large, and limited attempts have been made to integrate them into remote power systems. Capacity and rated power are generally determined by geographical considerations, and power response is quite good; however, most conventional pumped hydro facilities cannot quickly go from consuming energy (pumping) to providing energy.

Kodiak Electric Association (KEA) is considering pumped hydro as a way to permit greater penetration of wind on their grid. As part of the planned Pillar Mountain Wind Farm project, KEA is a grid-isolated utility with generation including a combination of diesel generators and hydropower from their Terror Lake project. KEA is planning to install 4.5 MW of wind (from three General Electric 1.5 MW SLE wind turbines) for the first phase of their Pillar Mountain project. A second proposed phase would incorporate three additional GE turbines and push penetration in excess of 60%, but this is expected to result in difficulty maintaining grid stability and frequency regulation. KEA is currently assessing options for incorporating pumped hydro, as well as a small, conventional battery storage system to absorb power variations and insure that power availability as a whole remains high.

Compressed Air Energy Storage (CAES)

An idea similar to pumped hydro is compressed air, which can also be used as a medium for storing excess energy. Air is compressed during times of excess energy and run through a turbine when power is needed. One major hurdle is finding a storage container of suitable size to hold enough compressed air to store a useful amount of energy.

Two plants are currently operational worldwide. In the Mackintosh, Alabama plant, large underground caverns in salt domes have been created by solution mining, which forms large scale, gas-tight volumes ideal for storing compressed air.

In Phoenix, Arizona, a compressed air storage system has been developed that uses solar energy to heat the air when it is being released, allowing more energy to be extracted from the stored air than the energy required to compress it. Some have suggested using mines in Alaska for compressed air storage, but compressed air storage works best at high pressures to maximize turbine performance. Leak rates cannot exceed 1%. In near-surface mines, porosity in rocks and fissures would likely allow too much air to leak; however, depleted natural gas wells might provide storage for compressed air in areas of the state where these wells occur, such as in the Cook Inlet basin. In most cases, current and planned CAES systems are installed in conjunction with natural gas-fired power plants, where the compressed air is not used to generate electricity directly, but is fed into the natural gas turbine to boot its efficiency.

As with pumped hydro, CAES capacity and rated power are generally determined by geographical considerations. Power response is also good and, depending on the design, can at least in theory quickly switch from generation to excess energy consumption. Because the storage capacity is determined by the volume of compressed air, CAES technology has been considered for long-term storage. At this point a small-scale CAES system is not commercially available, due in part to the cost of high pressure and the small storage capacity. For this reason, CAES is not likely to be useful for small communities until large-scale, cheap storage solutions are found.

Batteries

For electrical systems, batteries are the most direct way to store electrical energy. Batteries are used for many conventional systems, such as uninterruptable power supplies, cell phones, and laptops. Although large batteries are available for power supply, the amount of energy stored in typical batteries is much smaller than the amount of energy used in residential and commercial buildings, which means that many batteries need to be combined to provide appropriate capacity. Batteries are also relatively expensive. They have high maintenance cost and a limited lifetime – perhaps five to six years in most remote power applications. This means that the cost of storage (the cost of the battery divided by the total number of kW-hours of storage possible) is often much higher than the cost of generating new energy from fuel, which means that batteries are generally not appropriate for long-term energy storage.

Batteries are more appropriate for providing short-term energy storage to allow a transition between a variable renewable energy source and a dispatchable generator. This is the case in the wind-diesel power system in Wales, or smaller applications, such as home or small community systems, where the cost of dispatchable generators can be quite high. Since batteries operate on direct current (DC), a power converter is also required to allow them to supply (and be charged by) alternating current (AC). There are many types of batteries with different operating characteristics. Several battery types can be considered for rural applications.

Lead-acid batteries:

Lead-acid batteries are the most common batteries. People are accustomed to using them in vehicles. For remote power systems people typically use deep discharge batteries. These are inherently different from car starter batteries in that they are designed to hold larger amounts of energy for longer periods. Although batteries are highly reliable, they have a limited life, are heavy to ship, and contain toxic materials that usually require removal at the end of their useful life.

There are many different types of lead-acid batteries, and they come in many sizes. There are also many different designs, each of which has different operation and cost considerations, but also have differing life cycle performance. As a general rule, the larger and heavier the batteries, the better they are for remote applications, as they typically have higher amounts of lead (longer lasting active material) and more room for electrolyte. Lead-acid batteries have a moderate power density and good response time. Depending on the power conversion technology incorporated, batteries can go from accepting energy to supplying energy instantaneously. Lead-acid batteries are highly impacted by temperature and must be well maintained to achieve maximum life expectancy.

There have been some diesel battery hybrid power systems installed in the state, most notably at the new visitor center in Denali Park. The diesel generator charges the system at night and permits visitors the experience of silence during the day.

Other examples include a 1.4 MWhr system installed in Metlakatla and a 2.25 MWhr system installed at Chena Hot Springs in conjunction with their geothermal power plant. Both systems were installed for load leveling to improve the quality of delivery, although the customer in Metlakatla who spurred the installation shut down three months after the battery bank was brought online. That battery now supports the total Metlakatla load. It is charged almost exclusively by storage hydro, displacing diesel generation. The original battery cells have reached the end of their life and are being replaced. In an additional project, a battery bank was installed in Lime Village to store energy from its solar array. Unfortunately that system has experienced repeated failures, which is not encouraging for the installation of batteries in rural Alaska.

Ni-Cad Batteries:

Nickel-cadmium batteries (Ni-Cad) are an alternative to lead-acid batteries. They are more robust, with longer life in stationary applications. Although Ni-Cad batteries are considerably more expensive than lead-acid batteries, this longer life expectancy and their usefulness in high power applications might make them less expensive on a life-cycle basis, particularly in rural Alaska where long operating life is beneficial.

In 2003, Golden Valley Electric Utility in Fairbanks installed a Ni-Cad battery system capable of providing 27 MW of power for 15 minutes. This is long enough for the co-op to bring backup generation online in the event of problems with the Intertie or power supplied from the Anchorage area. GVEA's system has been operating successfully since installation and, as of mid-2008, has prevented 256 outages. A Ni-Cad battery bank was also installed as part of the high-penetration wind-diesel system in Wales to provide approximately 15 minutes of community load. This allows the system to ride out small lulls in wind production when the diesel engines are not operating and start a diesel engine if the lull is extended. Ni-Cad batteries are not as susceptible to temperature fluctuations, have good power density, very quick response time, and discharge consistently, making them appropriate for storage in wind-diesel applications.

Flow batteries:

Several battery technologies have been developed during the past several decades that can be classified as flow batteries. These batteries store energy in liquids that contain materials capable of storing electrons as compared to the electrochemical reactions that drive more traditional battery systems.

Flow batteries act much like fuel cells, where electrons are exchanged over a membrane, causing an electric current. The electrolyte is usually kept in large tanks, and although the battery itself has no moving parts, pumps are required to move the electrolyte past the membrane. This fact allows the decoupling of power output and storage capacity that is found in most other batteries: a flow battery can be designed to provide a specific power output (by determining the membrane surface area and electrolyte flow rate) and specific capacity (the size of the electrolyte storage).

The VRB (Vanadium Red-ox Battery) is one of these battery types, produced by VRB Storage Systems (Canada). This technology is currently in the pre-commercial testing phase, with a small unit being tested at UAF for the past two and a half years and at several dozen installations around the globe. Several flow batteries have been implemented in remote applications, most notably in a wind-diesel application on King Island off the coast of Australia. Kotzebue Electric Company was also interested in purchasing a battery of this kind to operate in conjunction with its wind farm. Unfortunately, VRB Storage Systems recently went out of business due to lack of funding.

Other flow batteries include sodium bromine and zinc bromine systems. These share most of the same basic properties and also remain in the pre-commercial stage. Flow batteries usually have low power density, meaning it takes a lot of fluid to provide any significant capacity. They have long system lives, at least theoretically. Pumps and power electronics are the typical weak links. Most flow batteries also have fast response times and can be sized to meet a specific need.

Depending on the electrolyte type, flow batteries must be kept at a relatively constant temperature. The low self-discharge rate and ability to decouple power and capacity would allow flow batteries to be used for longer, multi-day, or even seasonal storage.

Other battery types:

Many other battery types have been investigated for use in remote applications, but their power density, response time, and cost have not made them economical when compared to the three types described above. Increased market focus on high-quality, lightweight, inexpensive, and high-power-density batteries for the electric and hybrid car markets will result in new battery types that hold promise for remote applications in the coming years.

Photo below: This flow battery is a 10kW VRB battery undergoing testing at the Alaska Center for Energy and Power.

Flywheels

A flywheel is a device that stores kinetic energy in a rotational mass. Flywheels are not new technology, but modern materials and other innovations are spurring research on making flywheel systems that are smaller, lighter and cheaper, with greater capacity.

Flywheels have been used in applications including energy storage such as uninterruptable power supplies, grid conditioners for high-cost manufacturing, and even vehicle powering. (The gyrobuses used in Sweden in the 1950s were powered by flywheels.)

Flywheels have storage characteristics comparable to batteries in that their capacity is generally fixed but the capacity can be drawn down quickly or slowly depending on need. Often flywheels are used in remote applications to smooth out power fluctuations and allow the starting of a dispatchable generator when necessary. As compared to batteries, typical storage times at rated power in the order of minutes are expected. Flywheels, however, have several advantages. They have long cycle life, require minimum maintenance, and have fast response time. Although the limit of strength of the material used for the spinning rotor places upper limits on speed and thus capacity, most commercial flywheels are modular. Both capacity and rated power can be increased by using multiple units.

There have been catastrophic failures from overloaded flywheels; however, these are typically in research settings. Although recent developments such as magnetic bearings have reduced losses, flywheels have a parasitic energy loss to keep the unit spinning and a relatively quick self discharge if additional energy is not provided.

PowerCorp (Australia) has successfully integrated its flywheel system with wind systems and wind-diesel hybrid projects, and for grid stability typically in mining applications. The use of flywheels has allowed wind-diesel systems to operate at reportedly high penetrations (as high as 90%) of wind power to offset diesel generation. In this scenario the flywheel, which ranges in size from 250 kW to 1 MW, acts as a spinning reserve and can provide frequency and voltage control.

Capacitors

A conventional capacitor is a passive electrical component that can store energy. Capacitors are commonly used in personal electronic devices to store energy to maintain the power supply while batteries are being changed. Capacitors have no moving parts, thus a very high cycle life, fast and consistent response, but low power density. This means that large capacitor arrays are required to store meaningful amounts of energy. Conventional foil-wrapped capacitors are used extensively on electric grids today to provide voltage support. While maintaining a very high cycle life (>100,000 cycles), electrochemical capacitors, also known as ultracapacitors and supercapacitors, are able to store significantly more energy than conventional ones, but less energy than pure batteries. Capacitors have a higher power capability than batteries, but they store much less energy. Both capacitors and batteries are systems with multiple components and high capital costs; however, capacitors and batteries can be distributed throughout the system and do not require any specific geology. Capacitors are also expensive, and currently there are no commercial manufacturers of large-scale capacitor storage systems.

Hydrogen

The use of hydrogen as a power system storage medium has received a great deal of attention in the last few years. Several remote wind-PV-hydrogen systems have been installed, where excess energy is converted into hydrogen using an electrolyzer and stored as a compressed gas. This stored energy is then either burned in a modified internal combustion engine or run through a fuel cell when renewable energy is insufficient to cover the load. Hydrogen systems are expensive because of the high quality hydrogen needed for most fuel cell applications, and the cost of suitable storage tanks. They have very low round trip efficiencies, typically around 30%. As with flow batteries, the rated power and storage capacity can be decoupled, with the fuel cell driving the rated power and the hydrogen tank size driving available capacity. When compressed gas is used, power density is usually good, but hydrogen systems do not typically have good response times. They are sometimes installed with a small battery bank to smooth out power fluctuations. Due to the ability to store hydrogen in external tanks, it is typically considered as a multi-day storage medium, although the high cost of current storage capacity limits hydrogen's use for longer storage times. At present the use of hydrogen storage has been primarily in technology demonstrations or experimental systems. Due to its cost, hydrogen is not economically viable given the current state of the technology. As costs come down, as component efficiency increases, and as lower cost storage media are introduced, hydrogen may become a more viable storage medium for remote power systems.

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Web-based resources

European Union Benchmarking Project on components for Renewable Energy Systems: www.benchmarkingeu.org

RESDAS: Renewable Energy Systems Design Assistant for Storage: http://www.ecn.nl/resdas/

In-Stream Hydrokinetic Energy Technologies (In-River, Tidal, and Ocean Current)

AEA Program Manager: David Lockard (771-3062)

Alaska's first in-stream hydrokinetic turbine, located in Ruby.

TECHNOLOGY SNAPSHOT: HYDROKINETIC	
Installed Capacity (Worldwide)	1500 kW worldwide, all demonstration projects
Installed Capacity (Alaska)	0 kW installed
Resource Distribution	Potentially available to communities in all regions of Alaska located near a major waterway or tidal basin, excluding the North Slope
Number of communities impacted	Not assessed yet
Technology Readiness	Pre-commercial to early commercial
Environmental Impact	Impacts on local hydrology and aquatic species must be assessed on a case by case basis. AEA anticipates that these impacts can be minimized by appropriate siting, design and operation.
Economic Status	A 2008 EPRI study calculates paybacks in the 3-9 year range for three proposed hydrokinetic sites in Alaska, however this has not been verified by a commercial installation.

Hydrokinetic devices are powered by moving water and are different from traditional hydropower turbines in that they are placed directly in a river, ocean or tidal current. They generate power only from the kinetic energy of moving water (current). This power is a function of the density of the water and the speed of the current cubed. The available hydrokinetic power depends on the speed of the river, ocean, or tidal current. In contrast, traditional hydropower uses a dam or diversion structure to supply a combination of hydraulic head and water volume to a turbine to generate power. In order to operate, hydrokinetic devices require a minimum current and water depth. The minimum current required to operate a hydrokinetic device is typically 2-4 knots. Optimum currents are in the 5-7 knot range. Water depth is an important factor in the total energy that can be extracted from a site, since rotor diameter is dependent on adequate water level above the installed device. Hydrokinetic devices are ideally installed in locations with relatively steady flow throughout the year, locations not prone to serious flood events, turbulence, or extended periods of low water level.

Alaska has significant potential for hydrokinetic development in both rivers and tidal basins. Most inland communities in Alaska are situated along navigable waterways that could host hydrokinetic installations, and Alaska, with 90% of the total U.S. tidal energy resource, is home to some of the best tidal energy resources in the world.

While there are obvious opportunities, there are also significant environmental and technical challenges related to the deployment of hydrokinetic devices in Alaska's rivers and tidal passages. Some of these are common to installations in any location. Other concerns are more specific to Alaskan waters.

Some challenges facing hydrokinetic device deployment

- Environmental concerns, especially with regard to impacts on fish must be addressed. Fishery resources in Alaska have unparalleled value for subsistence, sport, and commercial use. It is critical that hydrokinetic energy development be fully evaluated for impacts on these resources.
- Survivability and performance issues must be examined. Alaskan waters have many hazards for hydrokinetic devices, including high rates of sediment transfer in river beds, debris, and ice. These issues also complicate the design of anchoring and cabling systems.
- Resource assessment is necessary. There is a shortage of river velocity and depth data, particularly for winter months.
- Effects on navigation are important. Many of the fast flowing rivers in Alaska with potential for hydrokinetic development are also major waterways for barge delivery of bulk materials to isolated communities. A major consideration is that these devices not impede river traffic.

As of 2008, hydrokinetic devices are considered pre-commercial. The Yukon River Inter-Tribal Watershed Council installed a 5 kW New Energy Encurrent turbine in the Yukon River at the community of Ruby for one month in 2008. A 100 kW UEK turbine is planned for installation in the Yukon River at Eagle in 2009. The New Energy EnCurrent machine, in 5 and 10 kW size, is available for purchase from ABS Alaska in Fairbanks, and New Energy Corporation is developing 25kW, 125kW, and 250kW devices as well. This technology is still being refined for Alaskan applications. Its performance is unproven.

Hydrokinetic devices typically use vertical or horizontal axis turbines similar to those developed for wind generation; however, because water is approximately 850 times denser than air, the amount of energy generated by a hydrokinetic device is much greater than that produced by a wind turbine of equal diameter. In addition, river and tidal flow do not fluctuate as dramatically from moment to moment as wind does. This predictability benefit is particularly true for tidal energy. It can be predicted years in advance and is not affected by precipitation or evapo-transpiration.

In Alaska's riverine environments, water flow fluctuates, often dramatically, on a seasonal basis. Snowmelt from glaciers and seasonal snow accumulation contributes significantly to the total water volume in Alaska's waterways. Generally, flow rates are the highest during spring snowmelt, but this higher flow is associated with significant debris flowing within the water channel. Debris is often directed to the fastest area of flow (the thalwag) and is not necessarily confined to the surface. In the winter, river flow often drops off dramatically and is largely supplied by local groundwater. This fact coupled with challenges associated with ice/turbine interactions leaves open to question whether hydrokinetic devices would be cost effective during winter months in most Alaskan rivers. If hydrokinetic devices are only deployed seasonally in riverine environments, an imbalance between resource availability and electricity demand (which is often highest in the winter months) will result.

It is possible that in dealing with resource and load fluctuations on short time periods, energy storage could be utilized or excess energy could be dissipated for heating purposes (see the Energy Storage section for more information).

Ocean Current

An ocean current is a continuous, directed flow of ocean water that can run for thousands of miles. Surface ocean currents (restricted to the upper 1000 ft or so) are largely wind driven, while deep ocean currents are driven by density and temperature gradients. Unlike tidal currents, which change direction and flow rate, ocean currents are relatively constant and flow in one direction only. In Alaska, the Aleutian passages have been identified as an area for potential development of ocean current energy extraction.

The type of turbine to be installed on an ocean current resource is similar to a tidal or in-river hydrokinetic one. As of late 2008, there are no commercial ocean current turbines in operation; however, several companies are exploring options for ocean-current energy extraction.

To put together a hydrokinetic project, the exact conditions of the project site must be determined. This process includes collecting information on river flow, depths, and fish data. Some of this data can be obtained from public sources.

Mapping Streamflow and Depths: Federal agencies including the USGS, the EPA, and the U.S. Army Corps of Engineers maintain detailed historic precipitation and runoff databases that are useful in project planning. In particular, the USGS has daily streamflow statistics for 485 sites around Alaska. This information can be found on their website at waterdata.usgs.gov/ak/nwis/sw.

Unfortunately, the gauging stations where these data are collected are often widely distributed, particularly in rural areas of the state. Additionally, because the amount of power that can be generated is a function of the cube of the velocity of the water: Power(kW) = $k(\text{velocity})^3$ where k=constant, the exact location of a hydrokinetic device within the water column will have a large impact on how much power is ultimately generated. It is recommended that local measurements of depth and water flow be obtained.

The best tool for measuring river or tidal flow in a specific location over time is the Acoustic Doppler Current Profiler (ADCP), which maps velocities at all depths through the water column. ADCPs are often deployed from a survey boat or barge. The timing of these surveys is important, and long-term data create a more accurate picture of the total potential. However, data collected by an ADCP can be adjusted using daily historical averages and extremes. This greatly reduces the time required to determine optimal locations.

Equipment can be readily purchased to measure local streamflow, however processing data requires some expertise. Alternatively, there are several companies that can conduct local resource assessments for both tidal and in-stream applications, as well as complete a bathymetric map of the floor of the water body (river or tidal basin). This is useful not just in determining water depth, but also in predicting how the flow through the channel might change over time, due to silting and/or flood events. It is important to remember that installing a hydrokinetic device will in itself change the flow of a river and can result in sediment deposition over the course of time.

Since they are relatively consistent and predictable from year to year, obtaining data on current flow for tidal energy resources is easier than for river environments. Basic data on Alaska's tidal energy resources can be obtained from the EPRI reports, 'Knik Arm Tidal Energy Report' and 'Southeast Alaska Tidal Energy Study.' In addition, there are data available from the Alaska Energy Authority on tidal energy resources in the Aleutians, Kodiak, Dillingham, and Bethel.

Environmental Assessment:

Directly or indirectly, any river or tidal turbine installation has the possibility of impacting fish, marine mammals, seabirds, and benthic fauna; however, these impacts are largely unknown. Direct impacts to aquatic organisms are primarily the result of contact with structures (such as turbines) placed in the immediate habitat. Such impacts may result in injury or mortality. Indirect impacts can include species displacement due to modified environmental factors that change migratory patterns such as a modified tidal stream that is relied upon for migration in and out of a bay or estuary.

One significant concern is potential impacts to Alaska's fish, particularly salmon. It is generally thought that hydrokinetic devices will have limited impact on adult species migrating upriver to spawn. They tend to favor slow water along banks rather than fast currents where hydrokinetic devices would be sited, and they would be better able to maneuver around an upstream diversion, which they could sense from turbulence and pressure changes. There is potential to affect outmigrating smolts. They tend to prefer the faster flowing waters where devices would be placed, and they would have less time to react to turbulence or pressure changes.

In any case, environmental impacts will be site specific. Until more information is gathered, a site specific environmental survey should be conducted at any location considering hydrokinetic power generation. The Alaska Department of Fish and Game conducts fish monitoring programs throughout the State, and there are several private companies that conduct surveys.

Potential Reduction in Cost of Energy

At this time there is minimal if any third party testing and verification of devices. Cost information is based largely on claims from manufacturers, who typically underestimate project expenses in the early stages of development. In fact, the turbine deployed by the Yukon River Inter-Tribal Watershed Council at Ruby in 2008 was the first hydrokinetic device to be connected to a grid anywhere in the United States in a river location. The first tidal current devices, six 34kW turbines, were installed in the East River of New York City in late 2006. There is more cost data available for tidal hydrokinetic applications installed in the northeastern United States, but to date these have all been demonstration projects and not permanent installations.

In order to assess performance and economics of hydrokinetic devices in river locations, the Electric Power Research Institute (EPRI) has established a baseline design for a hydrokinetic device consisting of a horizontal axis turbine mounted on a pontoon platform. Based on that design, a performance, cost, and economic model using a simple payback period (SPP) was developed. This model can be extrapolated to various sites of interest around the state. As is true with many technologies, the commercial scale economics are limited for rural Alaska, and small projects will yield higher costs per installed kilowatt. Nonetheless, EPRI calculated a simple payback period of 3 to 5 years for the isolated grid communities of Iguigig and Eagle. This is based on a system-level preliminary design of a plant anchored to the river floor (see Case Study #1), with two sets of two counter-rotating, 4.5 ft diameter rotors and a generator mounted on the rotor axis. The installed cost per kW of generation capacity is estimated at $7,500 for the 40 kW-rated plant at Iguigig and $5,800 for the 60 kW-rated plant at Eagle. The single 5 kW Encurrent project at Ruby was installed for $16,000 per installed kW.

While installation costs are high even in comparison to other renewable energy systems, they are not unexpected given the current level of development. In addition to capital costs, the economics of a project are also tied to other project costs including operation and maintenance (O&M), insurance costs, and permitting, design, and environmental monitoring costs. These could be substantial, especially for early generation installations. EPRI also states that initial project costs used in their analysis contain a margin of error of up to 30%, and operating and maintenance costs have a margin of error as high as 80%. This could dramatically impact the simple payback period and likely will vary from site to site.

Nonetheless, the results are compelling and indicate that, if barriers to development of the technology are overcome, hydrokinetic devices could result in a real reduction in electrical generation costs in remote Alaskan communities with an appropriate resource.

The following list includes developers who have, at a minimum, built an in-stream prototype hydrokinetic device:

Manufacturer	Location	Device Name	Website
BioPower	Australia	bioStream™	www.biopowersystems.com
Blue Energy	Canada	Davis Turbine	www.bluenergy.com
Bourne Energy	Malibu, CA	Riverstar	www.bourneenergy.com
Clean Current	Canada	Clean Current Turbine	www.cleancurrent.com
Current to Current	Burlington MA	Submersible Power Generator	www.currenttocurrent.com
Free Flow Power	Manchester, MA		
Hammerfest Strom	Norway	Hammerfest Strom Turbine	www.tidevannsenergi.com
Hydro Green Energy	Houston, TX	HydroGreen Turbine	www.hgenergy.com
Lucid Energy	Goshen IN	Lucid Energy Turbine	www.lucidenergy.com
Lunar Energy Ltd	United Kingdom	RTT	www.lunarenergy.co.uk
Marine Current Turbines Ltd,	United Kingdom	Seaflow SeaGen	www.marine turbines.com
Natural Currents	Highland NY	Natural Current Vertical Axis Turbine	www.e3-inc.com
Neptune Renewables	United Kingdom		www.neptunerenewableenergy.com
Oceana	Washington DC		
Ocean Flow Energy	United Kingdom	Evapod™	http://oceanflowenergy.com
Open Hydro	Ireland	Open Center Turbine (OCT)	www.flordahydro.com
Ocean Renewable Power	Fall River, MA	OCGen™	www.oceanrenewablepower.com
Pulse Generation	United Kingdom	Pulse Generation	www.pulsegeneration.co.uk/index.asp
Ponte di Archimeda	Italy	Enemar	www.pontediarchimeda.it
Seapower Int'l AB	Sweden	EXIM ™	www.seapower.se
Sea Snail	United Kingdom	Sea Snail	www.rgu.ac.uk
Scots Renewables	United Kingdom	SRTT	www.scotrenewables.com
SMD Hydrovision	United Kingdom	TidEl	www.smdhydrovision.com

Manufacturer	Location	Device Name	Website
Startkraft	Norway	Statkraqft	www.statkraft.com
Swan Turbines	United Kingdom	Swan Turbine	www.swanturbines.co.uk
Tidal Generation Limited	United Kingdom	Tidal Generation Turbine	www.tidalgeneration.co.uk/contact.html
Tidal Hydraulic	United Kingdom	Tidal Hydraulic Generator (THG)	www.dev.onlinemarketinguk.net/THG/ndex.html
Tidal Sails	Norway	Tidal Sail	www.tidalsails.com
Tidal Stream	United Kingdom	Tidal Stream Device	www.tidalstream.co.uk
UEK	Annapolis, Maryland	Underwater Electric Kite	www.uekus.com
Verdant Power	Arlington, VA	Kinetic Hydro Power System	www.verdantpower.com
Vortex Hydro Energy	Ypsilanti, MI 48197, USA	Vivaci	www.vortexhydroenergy.com
Woodshed Technologies	Australia	Tidal Delay™	www.woodshedtechnologies.com.au

Tidal Energy

Cook Inlet	Cook Inlet has some of the highest tidal ranges in the world and has been the subject of several studies. Ocean Renewable Power Company (ORPC) has received a preliminary FERC permit for its proposed tidal energy project site at Knik Arm, adjacent to Anchorage. ORPC plans to deploy a pilot project at Knik Arm in 2011.
Yakutat	The community of Yakutat is considering tidal energy.
Homer	The City of Homer and the communities of Port Graham and Seldovia are investigating the potential for tidal energy development in Kachemak Bay.
Dillingham	The Bristol Bay campus is assessing resource potential in Nushagak Bay.

In-river

Nenana	ORPC is planning the installation of a 50 kW turbine in 2009.
Whitestone	The community of Whitestone on the Tanana River near Delta Junction is interested in in-river hydro and has been the subject of an EPRI study.
Igiugig	Igiugig is a small community in southwestern Alaska that may be ideally suited to hydrokinetic power. It is the subject of one of the case studies in this chapter.
Ruby	The Yukon River at Ruby is the location of the first hydrokinetic installation in Alaska, the 5kW Encurrent turbine installed by the Yukon River Inter-Tribal Watershed Council. The YRITWC is considering deploying a larger 25 kW unit in 2010.
Eagle	AP&T has been planning the installation of a 100` kW UEK turbine for several years. Planned deployment is scheduled for 2009.

The Alaska Center for Energy and Power (ACEP) at the University of Alaska is seeking funding for the development of a Hydrokinetic Test Center in partnership with the University of Maine and Maine Maritime Academy (both active in tidal energy research). The proposed Center would work with communities and industry to develop protocols, standards, and best practices in environmental and resource assessment of tidal and in-river sites through the permitting process. The center would also work on modeling and performance testing of devices.

Case Study #1: Igiugig In-River Hydrokinetic Site (from EPRI study)

Igiugig, located 48 miles southwest of Iliamna and 56 miles northeast of King Salmon, is a small village with a year-round population of 56. Igiugig sits at the headwaters of the Kvichak River, which drains out of Lake Iliamna. Because it is located downriver from Lake Iliamna, Igiugig has much less summer/winter variability in flow. This location also results in a reduction in silt loads compared to rivers that are directly glacier fed. The Kvichak is ice free all winter at Igiugig, although ice does pose a concern for two weeks in the spring, as breakup occurs on Lake Iliamna. These factors make Igiugig an excellent candidate for hydrokinetic power generation.

EPRI has considered a hypothetical 40 kW project mounted on a 30-ft pontoon boat anchored to the riverbed. The pontoon was designed to serve as a platform from which four turbine rotors, 4.5 ft in diameter, could be suspended in the water column. A protective 'trash-rack' was mounted in front of the rotors and generator to minimize debris impacts. Three of these pontoons, with a total of twelve devices, were considered for this case study.

The 40 kW size of the project was based on village energy consumption (low) and resource availability (high) during summer months. The village currently has three diesel generators ranging in size from 60kW to 100 kW. Historic loads are 40 kW (summer) to 95 kW (December-February). The cost of power in the community is 98¢ per kWh and includes fuel and non-fuel costs.

Grid interconnection would be accomplished using a short (~225 ft) underwater cable from the units to the shore and connecting to the local grid via an existing distribution line. Other project components include a dedicated transformer, revenue metering, a disconnect device, a circuit interrupting device, a multifunction relay, and a real-time SCADA monitoring system.

Project costs in 2007 dollars were assessed through a model using historical quotes and existing projects in related technology fields. The capital cost for the 40 kW installation was estimated at $300,000, with annual O&M at $12,000 per year. Total annual energy production was estimated at 200,000 kWh (24 kW average, or 60% capacity factor). This was assuming the installation matched summer loads for Igiugug. The simple payback period was estimated to be three to four years under this scenario. A second scenario was considered in which the project provided baseload power to the village (325,000 kWhrs, 36 kW on average, or 90% capacity factor). This increased the capital and O&M costs for the project accordingly, but resulted in a similar payback period. Both scenarios were based on an avoided fuel cost of 65¢ per kW, which is the fuel portion of the current power cost.

Additional information on this hypothetical installation can be found in the EPRI report, 'System Level Design, Performance, Cost and Economic Assessment – Alaska River In-Stream Power Plants.'

Case Study #2: Cairn Point at Knik Arm Tidal Energy Site (from EPRI study)

Cairn Point is potentially a good location for in-stream tidal power generation, as strong tidal currents occur four times a day, and it is adjacent to significant electrical infrastructure at Elmendorf AFB and Anchorage. Cairn Point is located about two miles north of Anchorage in Knik Arm, in upper Cook Inlet. At Cairn Point, water depths exceed 150 ft, and the flow through Knik Arm is constricted. The constricted flow, along with Cook Inlet's large twice-daily tidal range, combine to produce high water velocities. Tidal currents average 2.0 knots with peaks of up to 7.5 knots. They are some of the strongest currents in Cook Inlet.

Challenges to successful deployment of an in-stream energy device at this site include seasonal ice, a high level of sedimentation in the water, a shifting seabed (scour), and also concern about impacts to marine mammals, particularly to the local population of Beluga whales. Due to the presence of seasonal pack ice, including both submerged and surface frazil ice as well as large blocks of beach ice (mixed sediment and ice), the support structure for turbines and the turbine profile must be completely submerged. Access to the turbine site for maintenance will likely not be possible from about November until breakup in March.

The EPRI system feasibility study considered two types of in-stream energy generation devices, the Lunar (RTT) and the Marine Current Turbine (MCT), installed in arrays that would produced an average of 17 MW of power with little environmental impact. 17 MW is the equivalent power used by about 12,000 homes, each using 1.3 kW. The array layout is determined by spacing rules designed to reduce cyclic blade stresses from seabed boundary layer effects, to prevent ice impacts, and to prevent lateral and downstream interaction between rotors.

The size and depth of a monopile into the seabed are determined by current and seabed properties. Site-specific surveys of water flow and geotechnical conditions will be required. The proposed installations could be accomplished from a derrick barge that would also be used to install monopile foundations and a remote-operated vehicle (ROV).   The ROV is used to monitor subsea operations, provide visual inspections, and carry out tasks such as connecting and disconnecting guide wires and electrical cables. The ROV can reduce cost and increase safety by eliminating the need to use divers in high current conditions.

The 17 MW size of the project was based on restricting power extraction to about 15% of the total available power to minimize degradation of the marine environment. If more of the resource can be extracted without degradation to the environment, then energy costs could decrease. Grid interconnection would be through a subsea cable (approximately 3000 ft long) to a shore-based substation, then to Elmendorf AFB's electric grid for transmission to Anchorage Municipal Light and Power.

Cost estimates in 2005 dollars are $110 million for the capital costs (not including a $3.25 million transmission upgrade), with an annual O&M cost of $4.1 million. This translates into nominal levelized costs of electricity of about 10.8¢/kWh for utility generation, and 8.4¢/kWh for municipal generation. This assumes energy incentives equal to those that the government provides for wind energy technology. At this point, Ocean Renewable Power Corporation has secured a FERC preliminary permit for the Cairn Point area. ORPC plans to install its own Ocean Current Generator (OCGen™) module consisting of four Turbine Generator Units (TGUs), each with 4 Advanced Design Cross Flow (ADCF) turbines mounted to a permanent magnet generator on a single shaft.

The system will be moored to the bottom with anchors and weights rather than pilings. It will be located at least 40 feet beneath the surface of the water to avoid conflicts with marine vessels, ice, and debris. ORPC plans to install a 1 MW pilot project in 2011, to increase to 5 MW after a year of testing and monitoring, and to increase to a final project size commensurate with the resource and energy market for the long term.

Additional information for the tidal in-stream power generation concept installation for Cairn Point can be found in the EPRI report, 'System Level Design, Performance, Cost and Economic Assessment – Knik Arm Alaska Tidal In-Stream Power Plant'.

The hydrokinetic working group agreed that commercial projects will likely be operating in the state in the next three to five years. The group was not ready to make specific recommendations for hydrokinetic projects for specific villages in Alaska. Recommendations from the working group are less project specific. They are tipped toward finding appropriate ways to move forward with this technology. The members of the working group stressed that its success is tied to not overestimating the maturity level of the technology by skipping over beta testing and demonstration phases.

Hydrokinetic energy represents a real opportunity for power generation using local resources at select locations in Alaska; however, there are still numerous environmental and technical challenges associated with this technology. For example, there are concerns related to interactions between turbines and both adult and juvenile fish, since most communities with hydrokinetic resources are heavily dependent on local subsistence and commercial fisheries. Additional concerns include ice interaction with infrastructure, silt abrasion,

Specific recommendations that came out of the working group include:

- Develop guidelines and protocols on how to initiate projects.
- Develop methods to prioritize potential projects.
- Conduct additional site-specific resource assessment in Alaska, including screening of locations with a list of compatibility factors, to determine optimal sites. This is necessary for project development and does not commit the state to failure by deploying technology too soon.
- Quantify and streamline permitting requirements, and draft a recommendation to have the state review FERC licenses. Encourage communities to protect their own interests by applying for site permits near their locations.
- Conduct more research as needed in terms of impacts on fish populations.
- Involve the University of Alaska as an independent source for device testing.
- Support demonstration and pilot scale projects to come up with defensible numbers (projections) for future project costs. Get data on how devices are working and how manufacturers can improve and modify devices. Optimize technology for Alaskan environments.
- Support development of a coordinated national research program to avoid multiple small failures in disparate locations. Position Alaska (possibly through the University) to take a leading role. Such a test center could also serve to promote cross-fertilization and standardization of ancillary equipment, such as development of a universal platform for installation of turbines, including a deployment strategy.

submerged debris which could damage turbines, navigation hazards, and impacts on marine life.

The actual construction and operation of a pilot device or devices will result in a more complete understanding of technical, environmental, and cost factors associated with hydrokinetic energy. This would provide a solid starting point for additional cost and economic analysis for specific sites around the state.

References

Polagye, B. and M. Previsic (2006) System Level Design, Performance, Cost and Economic Assessment – Knik Arm Alaska Tidal In-Stream Power Plant. EPRI – TP – 006 AK, 126 pp.

Previsic, M, Polayge, B and Bedard R, (2008) System Level Design, Performance, Cost and Economic Assessment – Alaska In-Stream River Power Plants EPRI RP-006-AK 99 pages

EPRI Primer on Power from Ocean Waves and Tides

Technology White Paper on Ocean Current Energy Potential on the U.S. Outer Continental Shelf, U.S. Department of the Interior

Ocean Wave Energy Technologies

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TECHNOLOGY SNAPSHOT: WAVE POWER	
Installed Capacity (Worldwide)	Over 3000 kW worldwide, most are demonstration projects. A commercial multi-unit 2.25 MW capacity commercial wave farm was commissioned offshore of Aguçadoura, Portugal in the summer of 2008
Installed Capacity (Alaska)	0 kW installed. Estimated recoverable resource of about 150 TWh/yr in southern Alaska (assuming 15% recovery at 80% generation efficiency)
Resource Distribution	Potentially available to communities in regions of Alaska located near an ice-free ocean and exposed to long fetches. The potential for wave energy development in protected waterways, such as those found in SE Alaska, or under winter ice is limited.
Number of communities impacted	Not assessed yet
Technology Readiness	Pre-commercial to early commercial with an early commercial site of over 2 MW installed with a follow-on second stage of about 20 MW in development
Environmental Impact	Impacts on local hydrology and aquatic species must be assessed on a case-by-case basis. EPRI anticipates that these impacts can be minimized by appropriate siting, design and operation.
Economic Status	A 2007 assessment of energy costs for conceptual wave power projects in North America ranges from about 10—39 ¢/kWh with the potential to decrease to about 4¢/kWh with installed capacities of 40 MW or more (consistent with price trends seen for wind energy) [Bedard et al., 2007]

The wind acting on the ocean's surface generates waves. They can travel for thousands of miles with little loss of energy until they near a shore where they begin to interact with the seafloor at depths of about 600 ft. Ocean waves consist of water particles that move in an orbiting pattern. Most (95%) of the wave energy occurs between the surface and a depth equal to one quarter of the wavelength.

Alaska has significant potential (estimated at about 60% of the total U.S. potential) for ocean wave energy development in offshore ocean basins near coastal communities.

There are obvious opportunities, but also significant environmental and technical challenges related to the deployment of ocean wave energy devices in Alaska's ocean basins. Some of these are common to installations in any location, and other concerns are more specific to Alaskan waters.

Worldwide as of 2007, ocean wave energy devices are considered pre-commercial to early commercial. Design, performance, and economic assessments have been made by EPRI for sites in Hawaii, Oregon, California, Massachusetts, and Maine. To date there has been no examination of wave energy project design for Alaska, although the City of Yakutat contracted with EPRI in the fall of 2008 to perform a wave energy feasibility study. The only deployed wave energy project in the United States is a 40 kW buoy (PowerBuoy™) for a Navy – Ocean Power Technology project in Hawaii. An initial, commercial wave energy wave farm with 2.25 MW capacity has been developed 5 km off the coastline of northern Portugal near Aguçadoura with plans to further expand the farm to 20 MW (www.pelamiswave.com/).

Some challenegs to Alaskan waters include:

- Environmental concerns – especially with regard to impacts on fish and marine mammals.
- Survivability and performance – Alaskan ocean basins have many potential hazards for ocean wave energy devices, including intense storms, high ocean current, debris, and ice (atmospheric, pack, and frazil). These issues also complicate the design of anchoring and cabling systems.
- Resource assessment – there is a shortage of site-specific wave energy information.
- Effects on navigation – ship and barge delivery of bulk materials to both major and isolated coastal communities is common in Alaskan waters, so a major consideration is that these devices not impede marine traffic.
- Lack of transmission infrastucture and large electrical loads adjacent to the wave resources.

Ocean Wave Energy Technology Overview

Ocean waves contain energy both through water motion (kinetic energy) and due to the elevation of water as the waves crest (potential energy). On average, the potential and kinetic energies in a wave are equal, while the energy fluctuation is a function of the square of the wave height, the distance between waves, and the wave period. Wave energy fluctuates daily and seasonally, depending on when and where storms occur to generate deepwater ocean waves. Monthly averages can be used to estimate seasonal variations in wave energy, which are maximum in winter. Wave forecast models can approximately predict wave energy from one to three days in advance. Both the kinetic and potential energy of waves are utilized in the range of ocean wave energy conversion devices being developed or deployed. These devices either transfer water motion into mechanical action or use the wave height to create a potential energy head across a generator.

To put together an ocean wave energy project, exact conditions of the site need to be determined. This information includes daily and monthly wave heights and periods, extreme wave events, ice conditions, wind and ocean currents, depths, fish data, and commercial and navigational uses. Some of this data can be obtained from public sources. Information about Alaska coastal ocean basin conditions and characteristics can be obtained from the Alaska Ocean Observing System (ak.aoos.org), NOAA, and Coast Guard buoys among other sources.

Installation and operation of a wave power facility will affect the near-by environment, and it has the possibility of impacting fish, marine mammals, seabirds, and benthic fauna directly or indirectly. Other environmental effects may include the withdrawal of wave energy, atmospheric and oceanic emissions, visual appearance, conflicts with other uses, and installation and decommissioning of facilities. There is no actual environmental effects data available as of 2008 for Alaska or anywhere in the United States. Some studies are being conducted in Europe to examine potential environmental impacts of wave energy.

The following list includes developers who have, at a minimum, built a wave energy conversion prototype device:

Manufacturer	Location	Device Name	Website
Finavera Renewables	Canada	AquaBuOy	www.finavera.com/
Oceanlinx	Australia	Offshore OWC	www.oceanlinx.com
Float	San Diego, CA	Pneumatic Stabilized Platform	www.floatinc.com
Hydam	Ireland	McCabe Wave Pump	www.wave-power.com
Independent Natural Resources	Minnesota	SEADOG – water pump	
Pelamis Wave Power	United Kingdom	Pelamis	www.pelamiswave.com/
Ocean Power Technologies	Pennignton, NJ	PowerBuoy	www.oceanpowertechnologies.com
Ocean Wave Energy Company	Bristol, Road Island	Ocean Wave Energy Converter	www.owec.com
Ocenergy	Norwalk, CT	Wave Pump	www.ocenergy.com/
OreCon Ltd	United Kingdom	MRC1000	www.orcon.com
SeaPower Group	Sweden	Floating Wave Power Vessel	www.seapower.com
Teamwork Tech	Netherlands	Archimedes Wave Swing	www.waveswing.com
Wve Dragon ApS	Denmark	Wave Dragon	www.wavedragon.net
WaveBob Ltd	Ireland	Wavebob	www.wavebob.com
WaveGen	United Kingdom	Coastal and Offshore OWC	www.wavegen.co.uk
AW-Energy Oy	Finland	WaveRoller	www.aw-energy.com/

Potential reduction in cost of energy

EPRI estimates of the cost of energy (COE) for the first commercial-scale wave power facilities in the United States range from about 10¢/kWh to 39¢/kWh, based primarily on the wave energy potential and operating and maintenance costs at the various locations that were considered. These costs do not compare favorably with some other forms of renewable energy such as hydropower, but they are somewhat less than the costs for early commercial wind energy devices. EPRI estimates indicate that the COE for wave energy facilities will decrease along a learning curve that depends on knowledge gained with each cycle of device improvement and operating experience. The learning curve for wave energy devices is projected to fall below the wind energy learning curve. Both curves are a function of installed capacity.

Conclusion

Ocean wave energy could represent a real opportunity for select coastal locations in Alaska; however, there are numerous environmental and technical challenges associated with this technology. For example, there are concerns related to interactions between ocean energy devices and marine mammals and both adult and juvenile fish. Most coastal communities with wave energy resources are heavily dependent on local subsistence and commercial fisheries. Additional concerns are related to ice interaction with infrastructure, debris that could damage devices, navigation hazards, and impacts on marine life.

While construction and operation of ocean wave energy devices is not considered near-term for Alaska, it has the potential to meet small-scale energy requirements for remote coastal communities. Feasibility studies like those done for in-stream hydrokinetic energy generation will be needed to provide a better understanding of the potential for and challenges of ocean wave energy generation.

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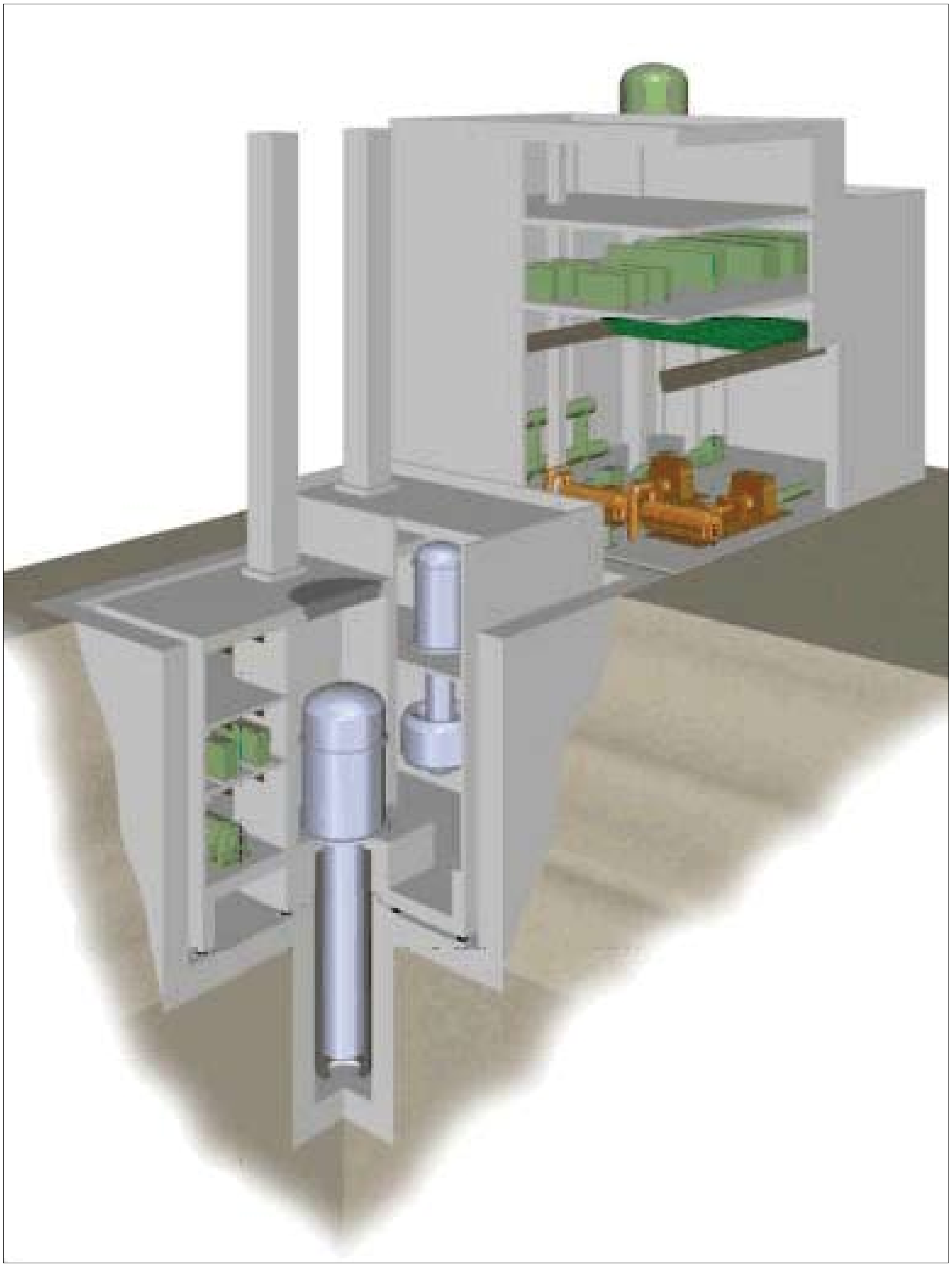
Small-Scale Nuclear Technologies

AEA Program Manager: Mike Harper (771-3025)



Worldwide, more than 15% of electricity is generated from nuclear power, with the United States, France, and Japan being leaders in this technology. According to the International Energy Agency, as of 2007 there were 439 nuclear power reactors operating in 31 countries. As nuclear power generation has become established since the 1950s, the size of reactor units has grown from 60 MW to more than 1300 MW, with corresponding economies of scale in operation. At the same time many hundreds of smaller reactors have been built, both for naval use (primarily in submarines) and as neutron sources, yielding enormous expertise in the engineering of small nuclear units.

Conventional nuclear technology is considered a mature technology. Significant progress is also being made in the development of small-scale, sealed, self-contained nuclear reactors, which can essentially operate as a 'battery' to supply energy in the form of electricity and/or heat. These modern, small reactors for power generation are expected to have greater simplicity of design, the economy of mass production, and reduced siting costs. They are also designed for a high level of safety in the event of malfunction and may be built independently or as modules in a larger complex, with capacity added incrementally as required. The International Atomic Energy Agency (IAEA) defines 'small' as reactors under 300 MW. To put this in perspective, 'small' is over 25% higher than the current peak power demand in the greater Fairbanks area (on the GVEA grid).

Small nuclear reactors are an intriguing emerging technology option for Alaska. Unlike conventional reactors, these nuclear 'batteries' are designed to be delivered to the site, installed with the generator system, and operated for the prescribed life (typically 5-30 years). After this time period, the fuel assemblies are removed and returned to the manufacturer, and the reactor assembly is refueled or shipped to disposal intact.

This type of fueling protocol allows plants to be simpler and less expensive to design and build. For designs that have no onsite spent nuclear fuel, the security requirements are reduced. The safety systems are passive and highly reliable without maintenance. The plants emit no greenhouse gases and can be small enough to be buried to minimize security issues. The power plant could be transported by barge in modules and installed in a building, with an excavation for the reactor vessel and containment system as deep as 100 ft deep.

There are a number of potential applications for these nuclear 'batteries' in Alaska. One of the most obvious would be to supply power for remote mines where diesel power would otherwise need be imported at high cost. Six of this type of reactor have been proposed for the Alberta oil sands region to provide heat to facilitate separation of oil from the sands. Power generation for remote communities is another potentially attractive application. The community of Galena has been working with Toshiba on obtaining a reactor for a number of years, and several other Alaskan communities have expressed interest in this technology. Galena is interested in a 10 MW reactor system, the 4S; designed by Toshiba to provide power and heat to the community. The city has passed a resolution supporting the installation of this reactor.

Potential Reduction in Energy Cost

The economics of the Toshiba 4S reactor appear compelling, especially given the current cost of electricity at 70¢ per kWhr (from the 2007 PCE Report) and estimated heating fuel cost at $7.48 per gallon (based on ISER data) in Galena. The expected cost of electricity from the 10 MW-size 4S is between 10¢ and 20¢ per kWhr. The final cost of delivered power is likely to vary based on a range of issues yet to be addressed related to the building of a nuclear plant in Alaska. Cost will also depend on the degree to which district heating and other uses can be found for the waste heat from the turbine generator system. While the Toshiba reactor can make 10 MW of electricity, it can simultaneously make 17 MW_{th} (58 MMbtu) of thermal energy in the form of warm (~ 150º F) water.

The 4S reactor is currently at the beginning of the licensing process with the U.S. Nuclear Regulatory Commission (NRC). This work is funded by Toshiba. The company expects to submit the design certification application for the 4S sometime in 2009, which will initiate the process that will ultimately result in a Design Certification from the NRC. This process certifies that national experts have reviewed every aspect of the facility's design and that the vigorous, legally binding review process has been satisfied. In parallel, an environmental report on applying the technology to the site facility is prepared, reviewed, and approved. These factors are resolved in a standard review process, codified in 10 CFR 52 and referred to as the combined licensing application (COLA). Seventeen applications for over 30 new nuclear reactors are currently undergoing this review process.

Environmental Considerations

The U.S. DOE has completed a 'Situational Analysis' for the community of Galena, including a preliminary environmental impact assessment. Compared to alternative energy sources, small nuclear plants are promoted as virtually disappearing into the background with little effect on the environment. Clearly, the permitting process under the Nuclear Regulatory Commission is an extremely rigorous one, which addresses potential safety and environmental concerns. Nonetheless, the Galena project would be the first installation of its kind and so contains inherent risks. For this reason, the Yukon River Intertribal Watershed Council, a consortium of 66 First Nations (Canada) and Tribes (Alaska) living along the Yukon River and dedicated to the protection and preservation of the Yukon River Watershed, has strongly opposed the Galena nuclear project.

While the Toshiba 4S is one example of a small nuclear reactor and the one closest to commercialization, there is a large variety of technologies with many proposed systems of a size appropriate for Alaskan applications.

Worldwide, over 40 small reactor concepts are being pursued, but with the exception of the 4S, they are all far from commercial. Below are some examples of developers and manufacturers who have received attention in recent years:

PBMR	The Pebble Bed Modular Reactor is a modular, high-temperature gas reactor that uses helium as its coolant. Its total output from 8 modules is 1320 MW. The PBMR is a reactor that has received significant attention. At a scale of interest for some of the larger mine sites or communities, this product is further away from permitting (and thus commercialization) than the Toshiba 4S technology.
Hyperion	Hyperion Power Generation also touts a small, portable nuclear reactor ('the size of a hot tub') that would produce 27 MW worth of thermal energy. The system uses technology originally developed at Los Alamos National Laboratories, and now licensed by Hyperion for commercial development. The suggested $25 million price tag is considered too low by many following the technology, and Hyperion is far from development of a commercial product.
NuScale Power	NuScale is another company that has licensed a design developed by the University of Oregon. This reactor is essentially a scaled-down version of a standard reactor, sized at approximately 40-50 MW. It is also in the early stages of development.
S-Star	Lawrence Livermore National Lab has designed a small, contained nuclear reactor as part of its S-Star program, with a 10 MW prototype and expected final product size of 50-100 MW. This reactor is nowhere near commercialization.
IRIS:	The 'International Reactor Innovative and Secure' is a medium power (335 MW) reactor that has been under development for several years by Westinghouse in coordination with an international consortium. The most recent information is that the planned submittal of a design certification application for IRIS has been pushed back from 2008 to 2010. In addition, Toshiba is now the majority owner of Westinghouse so the future of the IRIS reactor is not clear.

If all goes well, the Toshiba 4S could be providing Galena with power, space heating, and excess capacity for economic development opportunities by about 2015. If certain hurdles are not overcome, however, a large amount of money and time will be spent without producing any new power capacity at all. In any case, nuclear technology should not be considered a near term solution for energy needs in Alaska.

An additional consideration with nuclear reactors is that at this time AEA/AIDEA regulations specifically preclude involvement in nuclear energy. These regulations could hamper deployment of the technology if and when it becomes readily available.

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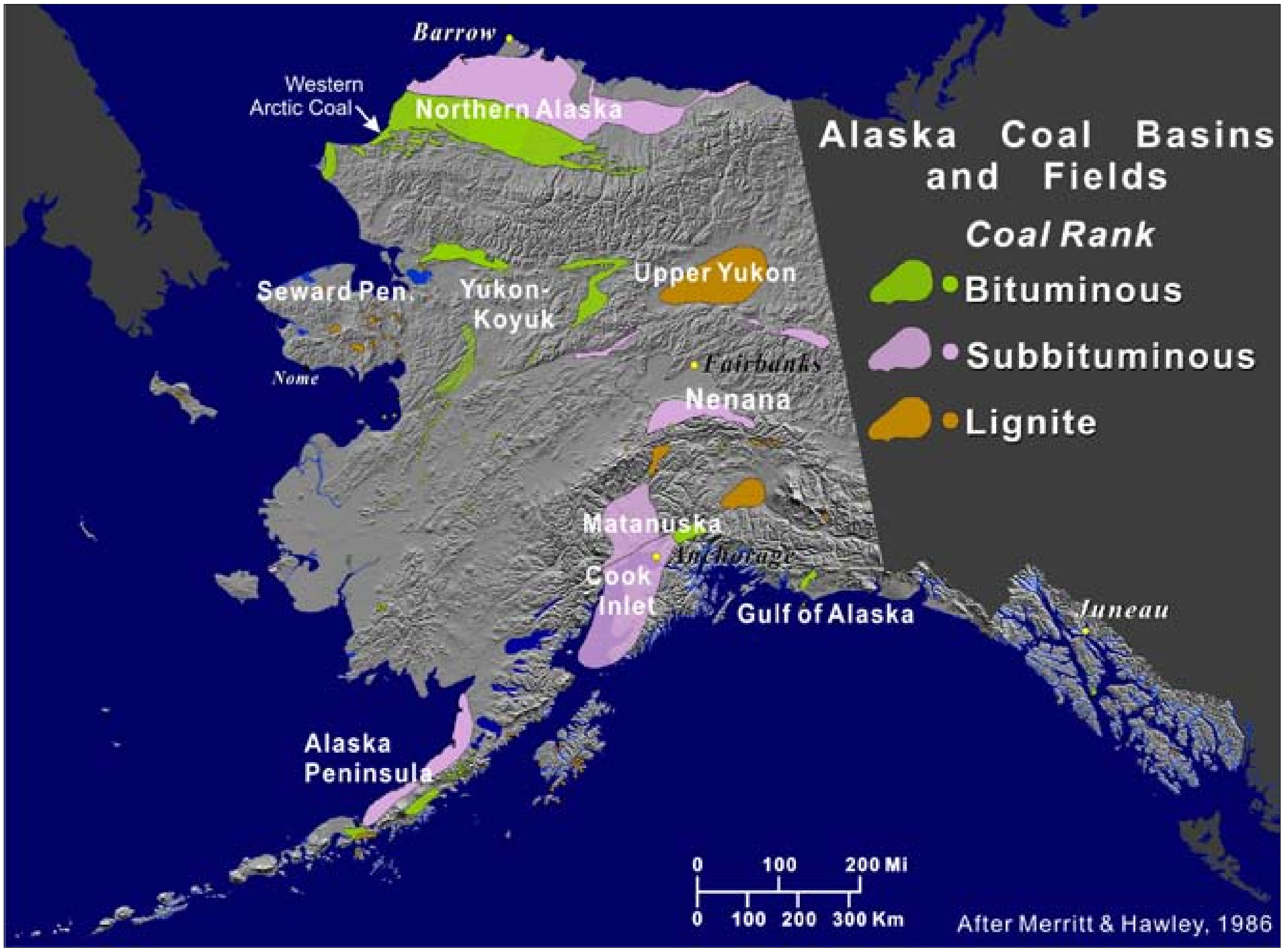


Alaskan coal resources are spread across coal basins and fields in the northern, interior, and southcentral regions of the state.

Coalbed Methane

AEA Program Manager: James Jensen (771-3043)

TECHNOLOGY SNAPSHOT: COALBED METHANE	
Current production (Worldwide)	Worldwide resources estimated between 3,000 to 9000 tcf. USA production is about 1.6 bcf from about 20,000 wells in 2007.
Current production (Alaska)	None
Resource Distribution	Coalbed gas is generally limited to sub-bituminous to bituminous coal rank. Coalbed gas content is unknown in most Alaska coal basins.
Number of communities impacted	Unknown
Technology Readiness	Successful and established commercial CBM production in Lower 48, however no production or infrastructure in Alaska yet. Production through permafrost is unproven
Environmental Impact	Water disposal must not adversely affect surface waters or subsurface aquifers.
Economic Status	Uncertain in Alaska

Coal is one of the most abundant non-renewable energy sources in the world, and Alaska has substantial coal resources. The majority of Alaska's coal is located in the North Slope, followed by the Cook Inlet region, Interior Alaska (mainly Healy), the Alaska Peninsula, Copper River Basin, and numerous smaller basins and individual coal localities throughout the state. Until 1981, gas in coal seams, or coalbed methane (CBM), was considered a dangerous hazard to underground mining operations and was vented to the surface. Beginning in 1981, this 'waste' methane was successfully produced, initially from underground mines, as a viable energy resource. Today the production of coalbed methane from coal seams in the Lower 48 accounts for about 1.6 billion cubic feet of gas, or about 10% of the gas production in the United States.

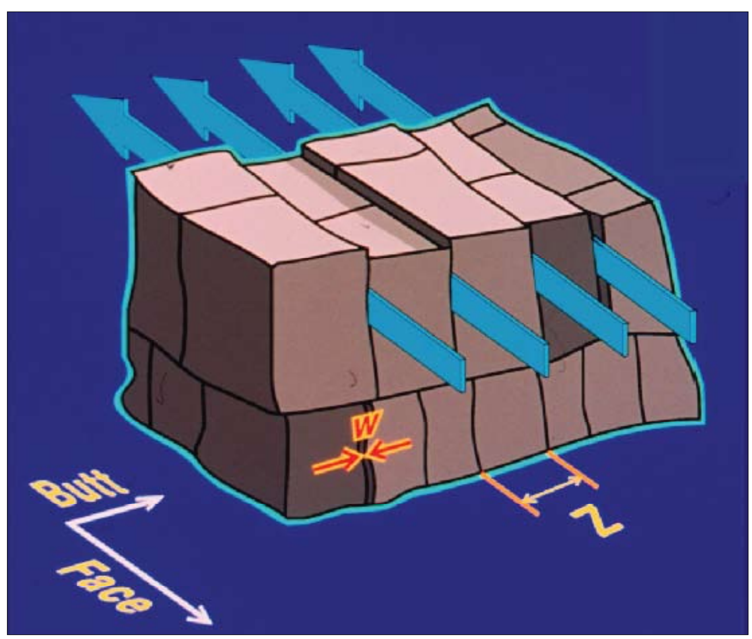
Coalbed methane is a clean-burning fuel, comparable in heating value (~1,000 Btu/scf) to conventional natural gas. Unlike conventional natural gas, with CBM the coal serves as the source rock and as the gas reservoir. Methane is formed along with water, nitrogen, and carbon dioxide when buried plant material is converted into coal by heat, pressure, and chemical processes over millions of years. This coalification process generates methane-rich gas, which often is held in pores, fractures, and spaces within the coal reservoir. As a reservoir, coal is a microporous hydrocarbon mineral capable of holding a large quantity of gas that is generated internally. This gas cannot be extracted from the coal reservoir unless these small micropores are connected through a well-developed fracture system called coal 'cleats.'

Permeability is the measurement of how well a fluid or gas moves through a rock when the pores are connected through a cleat or fracture system. Even if there is sufficient coalbed gas, it cannot be produced if there are few fractures resulting in low permeability.

Coal must also reach critical threshold of thermal maturity or 'coal rank' before large volumes of thermogenic methane gas are generated. Lower rank lignite to subbituminous coals contain mostly biogenic gas. The gas results from bacterial action on organic material, in the same manner that methane is generated by bacteria in shallow garbage landfills.

It is important to note that there is no current production of biogenic gas from lignite coals because they lack a well-developed natural fracture system. Production of biogenic gas from very thick (50-200ft-thick) sub-bituminous coals is occurring in the Powder River Basin. There, gas contents average less than 35 cubic feet per ton. Most commercially viable coalbed methane production is from coals within the range of high volatile A bituminous to low volatile bituminous. These coals provide both optimum gas content (as high as 800 cubic feet of gas per ton) and well-developed, natural fracture cleat systems to provide a pathway to the well bore.

Finally, coal seams are usually saturated with water, with the hydrostatic pressure keeping the methane within the coal. Sufficient hydrostatic pressure must be present throughout the geologic history of the coal seam for gas to be retained. If pressure is reduced enough by erosion, uplift, or other means, the gas can escape from the coal leaving little or no gas behind.



The geology of the coal basin and coal seam reservoirs needs to be studied in considerable detail so that the coal rank, coal thickness and lateral extent, and degree of fracturing are known. Additionally, data on the quality of the coal seam water are important for disposal of produced water. Systematic coalbed methane field development is essential in order to maximize total gas production, field life, and profitability. Coalbed methane resources in some basins have been successfully exploited, while other basins with apparently similar geologic and hydrologic attributes have proven to be only poor to moderate coalbed methane producers. Therefore, many pilot wells need to be drilled before the productivity of the reservoir in terms of recoverable reserves for the average well and for the field as a whole can be predicted.

The usual method of producing methane from coal is to pump water from a well, reducing the pressure and causing the methane to 'desorb' and begin to flow from the coal. A key factor in the production of CBM is permeability of the coal seam. The coal must be very permeable to allow the gas to flow in large quantities through the coal to the producing well. At first, coalbed methane wells produce mostly water, but over time and under proper geologic conditions, the amount of water declines and gas production increases as the bed is 'dewatered.' Water removal may continue for several years.

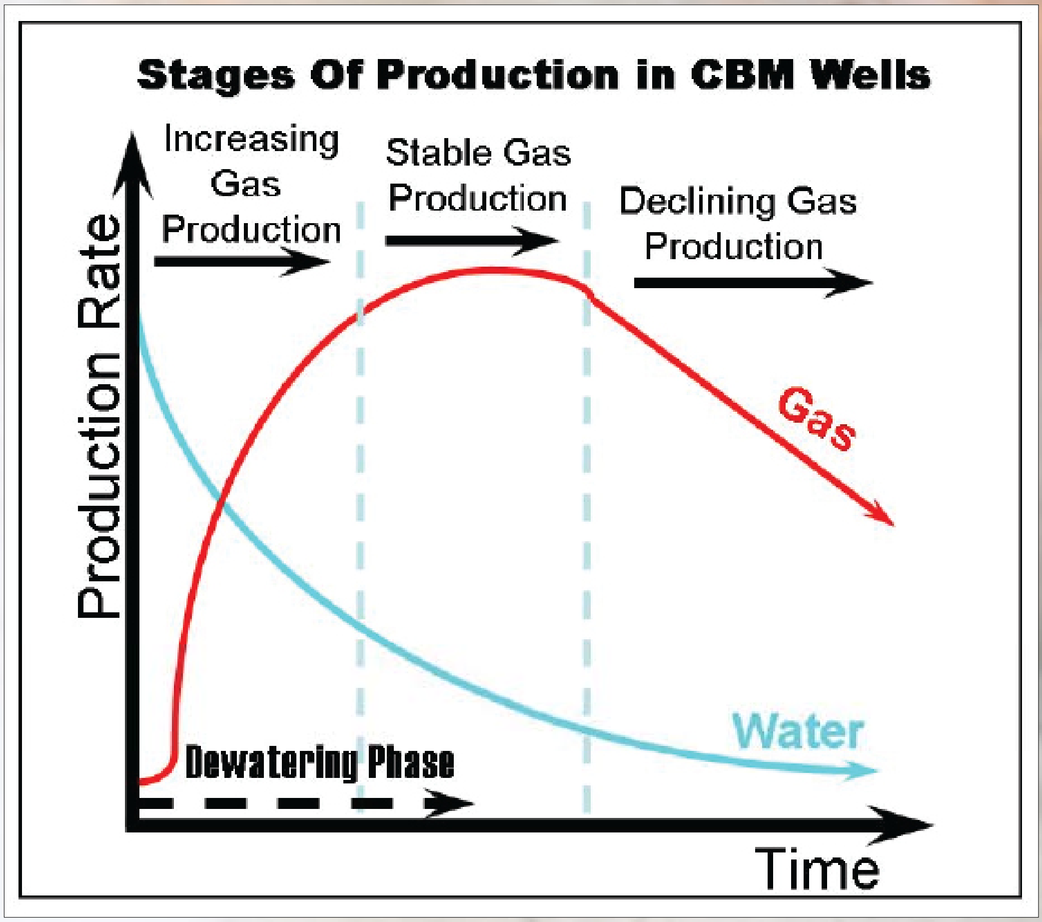
A developed coalbed methane well field consists of production wells, gathering lines, separators, compressors, and water disposal facilities. In each development, water and gas from each well site are transported to a single site for water disposal, gas treatment and central compression, and then to distribution pipelines.

	Stach (1975)	ASTM (1983)	Scott (1995)	Coal Rank
lig				lignite
	0.38	0.38	0.38	
sub				subbituminous
	0.65	0.49	0.49	
hvCb				high-volatile C bituminous
	0.65	0.51	0.65	
hvBb				high-volatile B bituminous
	0.78	0.69	0.78	
hvAb				high-volatile A bituminous
	1.11	1.10	1.10	
mvb				medium-volatile bituminous
	1.49	1.60	1.50	
lvb				low-volatile bituminous
	1.91	2.04	1.91	
sa				semianthracite
	2.50	2.40	2.50	
a				anthracite
	5.00	5.00	5.00	
ma				meta-anthracite

Left: Natural fracture or cleat system in coal. Without cleats, coal is porous but NOT permeable, and gas cannot be produced.

Understanding the detailed geology of coal deposits is essential in evaluating prospective coalbed methane fields in Alaska. These geologic evaluations are important for determining the coal rank, quality, thickness, continuity, and pertinent characteristics of the surrounding rock layers, as well as of the basin's hydrology. The ability for coal to produce methane as a resource is governed by the following critical controls: tectonic/structural setting, deposition environment, coal thickness and distribution, coal rank, gas content, permeability, and hydrogeology. Initial data collection activites to evaluate a prospective coal basin are detailed geologic mapping, collection of coal outcrop samples for coal quality and rank measurements, and measurement of fractures or cleats within the coals. The next step is drilling test holes to collect gas content data, measure permeability, and sample for water quality.

Few of the coal basins in Alaska have had this level of detailed study to determine whether they are viable candidates for coalbed methane production. Nearly all lack data on coal seam thickness, fracture spacing, and coalbed gas content. Coal quality data are sparse. As previously mentioned, coal rank is important because it directly influences the coal's gas storage capacity. With the exception of the North Slope, Alaska Peninsula, northern Cook Inlet, and a few other areas, many of the coal basins that underlie or are adjacent to Alaska rural communities have not yet reached a depth of burial and a level of maturity to form thermogenic coalbed methane, nor have they developed adequate fracture systems. These basins with lignite coal are not viable candidates for CBM with today's production technology.



There is currently no coalbed methane production or developed coalbed gas infrastructure in Alaska. Attempts to explore and economically produce coalbed gas in the northern Cook Inlet region met with limited success. In 2004, a government-funded coalbed methane exploratory hole was drilled at the community of Fort Yukon. The exploratory hole reentered a previously drilled hole in order to sample two low-rank lignite seams and collect samples to measure gas content. This followed a shallow seismic study conducted in 2001. It had determined that the lignite was laterally continuous beneath the community.

The results of the gas content measurements were disappointing, as the upper coal seam averaged 13% cubic feet per ton of gas; the lower lignite 19% cubic feet per ton. Testing indicated that the permeability of the lignite was extremely low with few fractures present within the lignitic coal seam. This project, including a preliminary seismic study and a single core test hole, cost in excess of $1.7 million. The importance of this study was that it demonstrated that low-rank lignite coals that are prevalent in many of Alaska's coal basins are not candidates for economically viable coalbed methane production.

In 2007 the Department of the Interior (USGS and BLM) conducted exploration for coalbed methane at Wainwright, Alaska on the western North Slope. Their initial results were promising, and in 2008 they drilled a delineation well to test the lateral extent of the coal beds, as well as an array of wells for a production test. Coals in the subsurface at Wainwright are bituminous in rank and appear to have generated sufficient methane to merit continued testing in 2009. Based on the known characteristics of the western North Slope coal (optimum rank, thick and laterally continuous seams, and sufficient gas content and burial depth), this region contains the best potential for coalbed gas production in all of Alaska.

In addition to finding coal of sufficient rank and gas content, there are other, unique challenges to coalbed methane production in Alaska. Given that coal bed methane production often involves significant water production, there must be some way to dispose of the fluid, especially if it does not meet strict EPA quality standards. The biggest challenges to production and disposal of this water are cold temperatures and permafrost. Usually, produced water is either surface disposed in large evaporation ponds, surface discharged into existing bodies of water, or re-injected into deep disposal wells. Evaporation ponds are common in many Lower 48 production facilities, but they are not a plausible option for Alaska because of the long freezing-cold winters. Surface discharge of even high quality water into rivers or lakes is unlikely to be viable because these streams are frozen about 70 % of the time, and such a practice is likely to be restricted due to possible impacts on fish habitat. Downhole re-injection of produced water is also problematic because the effects of disposal in permafrost are unknown. A well bore can freeze up during pump failure and cause significant problems that include gas field shutdown. Additionally, re-injection has a danger of fluid communication between aquifers if the subsurface geology is poorly understood and the rock layers are connected, resulting in contamination of a local source of drinking water. These hurdles can be overcome, but in Alaska it is important for developers to make special considerations which may result in significant additional costs.

Alaska has a significant portion of the coal resources in North America, and coal is by far the most abundant domestic energy resource available in the United States. Nevertheless, the occurrence of coal in an Alaskan sedimentary basin does not necessarily mean that subsurface coalbed gas can be economically produced. Subsurface coals need appropriate geologic and hydrologic characteristics to be CBM prospects. Lack of data on the geology, hydrology, subsurface water quality, coal quality, coal permeability, and gas content in most coal basins impedes assessing the coalbed methane potential in much of rural Alaska. However, there are areas that contain significant potential and could be explored and developed if the right incentives were available and plans developed. Detailed geologic field work and surface outcrop sampling is required in most areas before proceeding to the step of drill testing for gas content. The cost of obtaining coal gas content by drill coring is expensive, as much as $1 million per shallow drill hole as noted in the Fort Yukon experience. Additionally, the Fort Yukon project confirmed that the low-rank lignite coals present in a number of basins are not viable options for producing methane gas.

It is crucial that a proper assessment of all requisite geologic parameters be completed by qualified personnel before development decisions are made. A poorly conceived and executed CBM exploration program in rural Alaska could raise false expectations of the existence of a profitable resource where it is not geologically reasonable. Similarly, a poorly executed study could condemn a resource not properly assessed or evaluated for test sites. Like all energy resources, coalbed methane can be an excellent source of heat and power, but unique geologic conditions must be present, and rigorous scientific and economic evaluations need be performed before development can occur.

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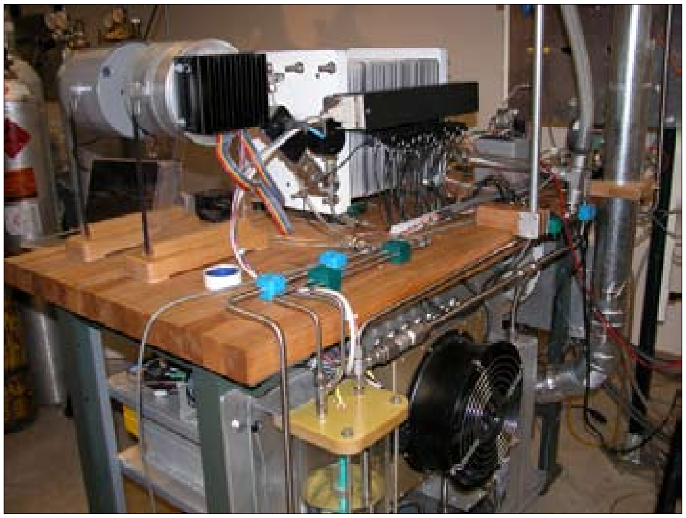
Fuel Cells

AEA Program Manager: Peter Crimp (771-3039)

Fuel cells are electrochemical devices that produce electricity and heat without combustion by combining a fuel with an oxidizer in separate half-cell reactions. Fuel cells are simple in construction, consisting of a “stack” of repeating components. They can be very efficient: hydrogen-oxygen fuel cells have a theoretical upper efficiency limit in excess of 70%. They can be pollution free (when operating on pure hydrogen) and have no moving parts in the stack (although moving air and fuel does require mechanical action, except on the smallest systems). Fuel cells are widely considered to be leading candidates for replacement of internal combustion engines in cars and for distributed power systems.

These features would seem to make fuel cells an ideal choice for efficient power generation, but fuel cells are not yet practical. They must jump a number of technical hurdles before being suitable for wide-scale use. For example, fuel cells have strict requirements for reactant purity and can be ruined if these requirements are not met. One type of fuel cell is intolerant of carbon monoxide and can be poisoned simply by the 1-2 ppm of CO present in ambient air. Other issues include cost and durability. The University of Alaska Fairbanks has been involved in the testing of approximately ten fuel cells in the last decade. Despite ideal laboratory conditions, all have failed. Causes of these failures included membrane failure, catalyst poisoning, control system problems, and design flaws. Also, despite their high cost, none of these systems has shown efficiency greater than that of a conventional diesel engine. Depending on design and manufacturer, efficiencies have varied from the low teens to the high 30s.

At this time, the only commercial fuel cell available is a 400 kW unit developed by UTC Power. These units are available at a $1,000,000 installed cost ($2,500/kW); however, this product operates only on natural gas, which is not a readily available fuel in most rural Alaskan communities. Even where natural gas is available, the capital cost for the fuel cell unit is higher than the capital cost for a natural gas turbine, and the efficiencies are approximately equal.



Fuel Cell undergoing testing at the University of Alaska Center for Energy and Power

Alternative Fuels

Program Manager: James Jensen (771-3043)

Waste vegetable oil products are a great source of energy for cars and trucks fitted with the conversion system.

TECHNOLOGY SNAPSHOT: ALTERNATIVE FUELS	
Fischer-Tropsch Fuels	Potential to produce liquid fuels at lower cost than petroleum based fuels. Issues include CO_2 sequestration, high capital cost, and technology shortage
Propane	Based on construction of gas pipeline, Tanana is serving as pilot project
Fish Oil	Has been used economically by large fish processors, fish oil from smaller processors could have potential but has been slow to develop
Ethanol and Biodiesel	Rapidly evolving technologies with limited feedstock available at this time
Waste Oil	Limited resource availability
Hydrogen	Expensive to produce and store, pilot studies have not been shown to be economical
Ammonia	Requires very cheap electricity and diesel fuel costs above $10/gallon for consideration
Electricity	Possibility to use plug-in electric vehicles in areas of the state where the cost of electricity is low

The idea of producing or otherwise using alternative fuels is appealing. Liquid or gas-based fuel can be stored and transported similarly to existing petroleum-based fuels. Alternative fuels such as hydrogen, ammonia, or electricity are actually best thought of as tools to store energy until a time when it is more valuable, or to move energy to a place where it is more valuable. Alternative fuels such as fish oil, Fischer-Tropsch fuels, and biodiesel are simply fuels derived from underutilized resources.

Fischer-Tropsch Fuels

Fischer-Tropsch (F-T) fuels are liquid-phase synthetic fuels made from a feedstock known as synthesis gas. Synthesis gas, or syn gas as it is sometimes called, is a gas stream consisting of primarily carbon monoxide and hydrogen. Syn gas can easily be produced by gasifying coal or biomass, or by reforming natural gas. The F-T process was invented during the 1920s in Germany by Franz Fischer and Hans Tropsch. It was used by Germany during World War II to convert locally available coal into a liquid fuel. Today the F-T process is an established technology that has been utilized commercially in South Africa for many years to produce liquid fuels and feedstock for a wide variety of petrochemical products. In the last several years, as petroleum prices have risen and support for energy independence has grown, the F-T process has received renewed interest worldwide. Alaska, with its massive coal, natural gas, and biomass resources has taken part in this resurgence.

There are several, recently completed studies analyzing the opportunities for coal-to-liquids (CTL) or gas-to-liquids (GTL) projects in Alaska. The most recent was a study commissioned by the Fairbanks Economic Development Corporation (FEDC) after CTL technology was identified as a technology of interest by the Fairbanks Energy Task Force report dated December 2007.

This study was completed by Hatch Engineering and is available on the FEDC website. The report considers three different potential plants sized at either 20,000 or 40,000 bbl/d with a coal, or coal and natural gas feedstock. The report assumes a long-term supply of coal at $25/ton and a way to sequester CO_2 generated in the process. Given these assumptions, projected capital costs range from 4.1 to 7.5 billion dollars (+/-40%). With an assumed interest rate of return of 12%, the breakeven F-T product price ranged from $108/bbl-$138/bbl (Hatch Report, page 2). The United States Air Force has expressed some interest in locating this plant at Eielson Air Force Base. The plant would then provide the air force with a substantial amount of synthetic jet fuel. One of the largest unaddressed hurdles for this project is finding a cost effective method to sequester the massive amounts of carbon dioxide produced from this project.

Another possible location considered for a CTL plant is the Beluga coal fields on the west side of Cook Inlet. The advantage here is that the coal is currently a stranded resource, but close to a deep water port with export potential to the west coast of the U.S. and to overseas markets. CO_2 sequestration would still be a challenge, but there are depleted natural gas wells that may prove viable for long-term storage. ANGTL, LLC has been working to advance an 80,000 bbl/d plant in this area.

Using natural gas as a feedstock for F-T fuels is also a potential option for Alaska. Converting natural gas to synthetic petroleum and transporting it down the Trans Alaska Pipeline is one way to access the natural gas on the North Slope. Another option would be to use both coal and natural gas as feedstock. The primary advantage here would be that natural gas produces a syn gas that is high in hydrogen, whereas coal produces a syn gas high in carbon monoxide. By adjusting syn gas amounts from each source, the CO to H_2 ratio for the F-T conversion could be optimized. The Hatch study commissioned by FEDC considered a natural gas and coal feedstock scenario as one of the options, and they found it to be the economically preferable option assuming that the natural gas is available.

A third possible feedstock for F-T fuels is biomass. The primary advantage of using biomass is that the process would be nearly carbon neutral over the growth cycle of the biomass. For large scale plants such as the two described above, finding enough biomass and delivering it economically to the plant would be challenging. Given this problem, ANGTL and others have proposed smaller plants that use woody biomass or municipal solid waste as feedstock. At these smaller scales, the economics have not been proven. Most successful F-T technology licensors have shown little interest in Alaska. Nonetheless, biomass as a feedstock may have the most promise in rural Alaska, where a small plant would produce fuel locally and displace expensive diesel fuel. The operational and technological risk of such a plant would be high.

Given Alaska's ample supply of potential F-T feedstocks, the technology could have a future in the state; however, all potential projects face significant challenges related to CO_2 sequestration, high capital costs, and ability to attract demonstrated F-T technology licensors/vendors.

Propane

Propane is already used in rural Alaska, primarily for cooking. The Alaska Natural Gas Development Authority (ANGDA) is now assessing the feasibility of using propane in river communities across the state for electricity, as well as for space and water heating. They are using Tanana as a demonstration community to determine the feasibility of converting existing appliances, testing small co-generation systems, and converting heavy equipment and vehicles to run on propane.

The Yukon-Kuskokwim Propane Demonstration Project is designed to greatly expand use of propane in rural Alaska. This pilot project subsidizes propane costs to reflect the cost ANGDA anticipates, assuming a natural gas pipeline is constructed and a propalizing plant is installed at the Yukon River crossing. The feasibility study includes assessing the challenges associated with transporting propane by existing barge companies and using propane for electricity and space heating. Two 1000-gallon propane tanks have been delivered to Tanana as part of the project; however, there are some concerns with Coast Guard regulations regarding propane transport on navigable waterways.

While the cost of propane including delivery is not a major expense for rural Alaskans in the small volumes currently used, larger quantities do not demonstrate an economic benefit when used for space heating or power generation. Nonetheless, there are some benefits to propane over diesel fuels, primarily in terms of environmental concerns.

ANGDA's preliminary estimates suggest that communities could save money by using propane instead of other fossil fuels if the natural gas pipeline is built. The Tanana project is designed as a guinea pig to get a better sense of conversion costs and economic viability of the fuel.

Fish oil

Fish oil is a natural fuel that can be a co-product of the fish processing industry. The oil is rendered from fish waste using a multi-step process of heating, pressing, centrifugal separation, and filtering. Fish oil can be used either directly as a boiler fuel or converted into a biodiesel and used for diesel engine fuel and/or heating fuel. Raw fish oil is also being used by a number of fish processors around the state for onsite heating and power generation.

For the last couple of years The University of Alaska Arctic Energy Technology Development Laboratory (AETDL) has been testing fish oil biodiesel in a diesel gen-set. The results indicate that fish oil biodiesel can be used for diesel-based generation but that needs to be handled differently from standard diesel. Two of the biggest issues are its comparatively high cloud point temperature (34ºF) when solid waxy particles begin to form within the diesel fuel and plug delivery systems, and its tendency to oxidize more quickly than petroleum based diesel. Using oxidized fish oil biodiesel in a diesel generator can cause shellacking of fuel injectors and damage the engine's fuel handling system. Despite these challenges, fish oil and fish oil biodiesel can be a very economical alternative in communities where large quantities of fish oil is readily available. The recent rise in the cost of diesel fuel has created greater incentive to render fish oil to replace conventional diesel in rural Alaska. Alaska currently produces roughly 8 million gallons of fish oil each year. The majority of this oil is produced by the largest fish processors in the Aleutian Islands. Statewide, there is an estimated 13 million gallons of unrecovered fish oil each year.

This unrecovered fish oil is primarily from the fish waste of Alaska's many small fish processors. Individually, these processors do not have the throughput to justify the capital cost of fish oil rendering equipment. A portable fish oil rendering facility might provide a solution to this problem. For the last coupleof years, the Alaska Energy Authority has tried to encourage the development of such a module, but unfortunately its efforts have met with little success. Long distances between processing sites and short, overlapping fishing seasons are significant hurdles that hurt the economics of a portable fish oil rendering module.

Ethanol and Biodiesel

In the U.S., most ethanol is made from terrestrial food crops like corn and soy beans. These bio-fuels are considered first generation bio-fuels and are inappropriate for most of Alaska, due to their long growth cycle and energy-intensive production, to land usage, and to Alaska's climate and environmental conditions. There is a new push across the United States for second generation bio-fuels, which are more environmentally friendly and made from feedstock that is otherwise wasted or has little value. Options that have been considered for Alaska include cellulosic ethanol and algae biodiesel.

The raw materials needed to produce cellulosic ethanol are plentiful in most parts of Alaska. Cellulose is present in every plant, in the form of straw, grass, and wood. It could be harvested from local forests, or cellulose-producing crops could be planted on land considered marginal for agriculture, but biomass is not an energy dense feedstock for making liquid fuels, so transportation costs would be significant. In the Lower 48, the Department of Energy announced funding for six pilot cellulosic ethanol plants in 2007. These plants will require considerable financial support through grants and subsidies to operate, but the hope is that the technology will advance to where the process becomes economic and cost-competitive with other alternatives.

Over the last few years, algae biodiesel has received significant attention worldwide. This is due to algae's fast growth rate and high oil content. Much research is going into this potential feedstock for biodiesel; however, with Alaska's limited amount of sunshine the state has not been the focus of any of this activity. Alaska's current options for biodiesel feedstock are fish oil, and waste vegetable oil.

Waste Vegetable Oil

Biodiesel from waste vegetable oil or straight waste vegetable oil represents a limited opportunity in Alaska.

Only the largest communities, Anchorage, Fairbanks, and Juneau, have large enough quantities of waste vegetable oil to commercially utilize the resource. All of these communities have groups working toward developing this resource for biodiesel production; however, the volumes will always be small when considered from a statewide perspective.

In areas where even smaller quantities of waste vegetable oil are available, heating applications to be best. There are commercially available waste-oil burners that can burn waste vegetable oil and/or used motor oil; the smallest units available are rated around 100,000 Btu/hr and cost around $5,000.

Hydrogen

Hydrogen is not a source of energy, but a way to store energy. You don't mine hydrogen; you use electricity to make it. The ability to store energy is valuable in areas of the state with significant renewable energy resources but limited energy loads to make use of them. This scenario describes much of Alaska, where there is a nearly limitless supply of wind, wave, and tidal energy. Hydrogen could one day play a role in capturing that energy and transporting it to market. If this is ever to happen, cost reductions and/or efficiency gains need to be made in the areas of producing, compressing, and storing hydrogen. As hydrogen-related costs drop, markets can develop that utilize the hydrogen. For more information on hydrogen as an energy storage option, see the section on Energy Storage.

Ammonia (NH_3)

Ammonia has been used as a fuel in certain applications, to power buses in Belgium during World War II and to power the X15 rocket airplane, that set speed and altitude records in the early 1960s. Now ammonia has been proposed as an alternative to fossil fuels for internal combustion engines for stationary generator and vehicle applications. Ammonia is preferable to hydrogen in terms of energy storage, but it has approximately half the energy density of diesel. This means it requires twice the storage volume to achieve the same energy content. Nonetheless, ammonia is a viable alternative and it can run in most existing engines with only minor modifications to carburetors and injectors. Ammonia as fuel has no serious problems associated with it in terms of toxicity, flammability, or emissions. It is widely produced and distributed, although transporting ammonia over long distances would not be economical due to its lower energy content per pound. About 80% or more of the ammonia produced is used for fertilizing agricultural crops. The Agrium fertilizer plant on the Kenai Peninsula produced 280,000 tons of ammonia fertilizer annually from a natural gas feedstock and shipped the product to many countries across the globe. The plant shut down in 2007 due to shortage of natural gas supply in Cook Inlet.

Manufacturing ammonia onsite in rural Alaska is a possibility. It could be manufactured from renewable energy sources using an air separation plant to collect nitrogen (air is composed of 78% nitrogen), and an electrolyzer to generate hydrogen from water. In contrast to using the hydrogen directly, converting the hydrogen to ammonia eliminates the need for compression, as ammonia can be stored and transported as a liquid at reasonable pressures. This means that existing infrastructure could be used for handling, storing, and transporting without the need for exotic storage material. In addition, industry standards and regulations exist for the safe handling and storage of ammonia.

Optimistic Break-Even Point for Ammonia Fuel Production		
$ 4.10		$/kg H2
	58	% electricity cost
$ 1.72		$/kg assuming no cost of electricity
$ 336,713		cost per year for electrolyzer including capital and O&M
$ 1,779,766		full plant cost per year, capital and O&M only
$ 1,779,766		Annual value needed for capital recovery and operation
	1,221	tons ammonia produced per year
$ 1,457.15		break even cost per ton of ammonia
$ 75.19		Price per MMBtu for ammonia
$ 10.45		Equivalent price per gallon diesel fuel

Based on the expected cost of the equipment, ammonia would not become economic to use as a fuel until the cost of diesel reached $10.45 per gallon (see analysis above). This is an optimistic analysis based on commercial production of 4.5 Mmbbl per year and no electricity cost. A more realistic analysis calculated a break-even equivalent value of diesel fuel at $13.50.

Since diesel is not expected to reach this value, even in rural Alaska in the near future, this option does not appear economically viable unless the equipment cost (electrolyzer and air separation plant) is reduced significantly, or there is a pilot project where the capital costs are offset by grants.

Electricity

Electricity has the ability and, under some scenarios the economic justification to replace petroleum-based transportation and heating fuel. Over the last few years, as heating fuel prices have increased, Alaska has seen communities with cheap hydro-based power move towards greater use of electric space heating. This trend will continue in areas where plentiful supplies of renewable electricity cost less on a delivered BTU basis than heating fuel. In addition to heating, electric-power transportation is an emerging option. There are already commercially available electric vehicles, snow machines, and four wheeler. As battery technology improves, these vehicles will cost less and show improved range and efficiency. Plug-in electric vehicles may also provide great advantage to small grids that have access to intermittent renewable power. With continued technology development, the batteries of these vehicles may be able to stabilize the grid by drawing or dispatching power whenever there is a supply/load imbalance. This capability would allow small grids to use higher percentages of non-dispatchable renewable power without reducing power quality.

Snettisham Hydropower Plant near Juneau. Hydro power is some of the lowest cost energy in the state and can be used to displace high-cost heating and transportation fuels.

Explanation to Database Methodology

How to Read and Interpret this Report

This report is the result of a process begun in the spring of 2008 when the Alaska Energy Authority held a series of regional and community meetings to address the issue of rising energy prices. At that time, the climbing price of crude oil resulted in large increases in the cost of energy for residents throughout the state, especially for those remote communities.

At these community meetings, AEA director Steve Haagenson outlined a process that would involve collecting information from local communities to be synthesized into a single state energy plan. At the meetings, maps were created that showed where community residents were aware of possible local energy resources.

In addition to the information collected in the community meetings, several other sources of information have been used. AEA organized working groups based on technology: diesel efficiency, heat recovery, wind, hydro, biomass, geothermal, and hydrokinetic and wave energy. Each of these groups held meetings at AEA, with interested parties joining the discussion by phone. At the end of this process, a list of communities where each of these technologies might be applicable was created, along with estimates of the cost of using these technologies.

Another important source of information for this report is the PCE (Power Cost Equalization) program, designed to reduce the cost of electricity for residences in remote communities. Information collected in the administration of this program is the most complete data available for the state of Alaska. This data set contains information about diesel prices, electric prices, and consumption of electricity by a community. This information applies only to fuel used for power generation and it gives no indication of heating fuel prices or use, or fuels used for transportation.

Energy information collected by the Institute for Social and Economic Research (ISER) has been used to estimate the heating fuel and transportation fuel used in each community. However, because no process is in place for collecting this information, the data, based on extrapolations from values collected for 20 sample communities, is incomplete. As heating fuel costs are particularly burdensome for households in rural communities, this lack of data is a major weakness of this analysis. ISER has requested funding to address this issue by creating an energy information data network to collect energy cost and consumption data from all communities. It is hoped that future versions of this document will contain more defensible data.

Another source of information is the Department of Community and Regional Affairs. This department supplied a complete copy of their database for use in this database. The population data, location, culture, and history sections are taken directly from it. The United States Census data is taken from the same database, but from the 2000 census. New data will not be collected in the next census. This is a further argument for support of the ISER energy information data network.

Every attempt has been made to collect the most reliable information available for use in this report, so that it will be a useful tool for communities, utilities, funding agencies, and others to make good decisions about how best to provide energy to each community. However, the readers of this report must note that in many cases the reliability of the underlying data is not as robust as they might wish. This necessarily limits the utility of this tool. It is hoped that better data can be collected and that this database can be improved.

Layout of the Community Reports

This report is based on a community by community analysis and is divided into five basic sections: the cover page, the community description, analysis of the current energy situation, possible upgrades to the existing power plant, and locally available alternative resources.

Page 1 (Cover Page):

The cover page contains five basic items: the name of the community, a map of Alaska showing the location of the community, a pie chart and a per-capita table showing the estimated breakdown of energy use in the community, and two meters showing the current cost of energy as compared with possible alternatives.

Energy Use Pie Chart and Per-Capita Data:

The data in this pie chart is based on the PCE data collected and the ISER extrapolations for each community. As noted above, the PCE data is more complete and trustworthy than the other two components, but even the PCE data is sometimes incomplete. For example, Akutan PCE data reports only fuel consumed in the community power plant, but the community has a fish processer that operates its own power plant. The community population counts the people working at the fish plant. When these facts are combined, it appears that the energy consumption in this village is low on a per-capita basis, but this simply reflects the lack of data on the fuel consumption at the fish processer. Other communities, like Cold Bay, have the opposite problem: the census data indicates only 72 people in the community, but an average electrical load of 304 kW and high fuel prices. This results in a high calculated per capita energy cost.

The Electric and Heat Meters:

These meters are a graphical presentation of the results of the analysis of the current energy costs in each community normalized to $110/bbl crude oil and the calculated costs of alternatives. The most trustworthy numbers are the current costs for diesel-generated power and for heating fuel. These meters indicate when an alternative appears to be lower in cost than existing technologies (projects that might be favorable to pursue), as compared with projects that result in higher energy costs (ones that probably should be avoided). How these numbers are calculated is covered in the section below. The yellow background indicates the possible range of costs as the price of diesel fuel, with the bottom estimated at $50 per barrel, and the top at $150 per barrel.

Page 2: Community Information

If a community is in the PCE program, this will be indicated by a 'PCE' designation besidw this line. Some communities have been included that are not PCE communities, but the information that follows will be incomplete.

Current Energy Status-Electric (PCE)

This section begins with the most important and most difficult number in the plan: the ***Estimated Local Fuel Cost at $110/bbl*** in each community. The numbers included in this report have been estimated by ISER and AEA, and are the same as those used for evaluation in the Renewable Energy Fund reviews.

Utilities are required to submit receipts for fuel deliveries in order to get reimbursed from PCE, but three things affect the price they pay: the cost of crude oil at the time of purchase, the cost of shipping that fuel to that community, and the rates that the utility is able to negotiate with the fuel supplier. Some utilities have formed fuel-buying co-ops to increase their purchasing power in the market, and they have been able to negotiate better prices than others. AVEC managed to obtain a long-term fuel purchase agreement with their fuel supplier that locked in prices for several years and delayed the onset of higher fuel prices. This arrangement was good for AVEC and seemingly good for the state; however, a simple averaging of these fuel prices with other villages underestimates the cost of fuel in that village.

The transportation component is also a tricky number. In discussions with both utilities and fuel suppliers, the cost of delivering fuel to any given community is based on the distance and difficulty of delivery. These numbers are not published for antitrust reasons so they are not known to the writers of this report. Adding to the confusion is the way in which these numbers are reported to the PCE. For AVEC, fuel is purchased in five or six 'drops' at the refinery, then delivered to multiple villages. The fuel cost reported to PCE seems to be the price paid per gallon for that entire drop of fuel, and so it averages the cost of transportation over all the villages served by that particular shipment, regardless of the actual transportation cost calculated by the shipper. Add to that the rapidly changing price of crude oil in times of high volatility (like the past few years). The net result is a data set that seems to belie statistical interpretation.

One of the criteria of this planning process was to evaluate the cost of diesel power at $110 per barrel crude oil prices, so a model needed to be created that would estimate this number by community. However, when village fuel prices reported to PCE are plotted against crude oil prices and linear regressions are calculated, about 10% of villages have fuel prices below the refinery cost. Since this result cannot be real, fuel price values for these communities were adjusted upward. If some communities are statistically low, one suspects that an equal number of communities are statistically high, but no adjustments were made to these higher priced communities. It is also worth noting that many (though not all) of the communities that needed to be adjusted upward were AVEC villages, suggesting that the fuel purchase agreement has been very good for that utility.

Average Efficiency is calculated as the number of kilowatt hours sold (*Average Sales)* divided by the Consumption in 2007. A value of 14 kW-hours per gallon for small communities and of 14.75 kW-hours per gallon for larger communities is considered to be achievable. Values lower than this would indicate that efficiency gains could be achieved.

Consumption in 2007 is the total gallons of fuel used in the power plant and is taken directly from the PCE data.

Average Load is calculated as the *Average Sales* divided by the number of hours in a year from the PCE data.

Average Peak Load is estimated as twice the average load above.

Average Sales is the number of kilowatt hours sold per year and it is taken directly from PCE numbers.

Fuel COE (Cost of Electricity) is calculated as the *Estimated fuel cost at $110/bbl* divided by the *Average Efficiency*.

Est O&M is the estimated Operations and Maintenance costs for diesel generators, set at $.02 per kW-hr for every community, based on the experience od diesel operations in the state.

NF COE is the PCE reported *Non-Fuel Cost* divided by the number of *kilowatt hours sold* minus the $.02 for O&M.

This number is particularly inconsistent between villages, due to many factors, and has been the topic of many discussions about the PCE program. For example, if a utility borrows money to purchase a new generator, the cost of that purchase will be reflected in this number; but if the new generator was paid for by a grant from the Denali Commission, that purchase will not be included. Also, administrative support for billing and customer service is handled in a variety of ways in different communities. AVEC does not report these non-fuel costs by individual community, but rather provides an aggregate value to the PCE program.

Current Fuel Costs are based on the number of gallons consumed times the Estimated Local Fuel Cost at $110/bbl.

Estimated O&M is the number of kilowatt hours sold times $.02.

Other Non-Fuel Costs are from the PCE report, but adjusted by the O&M above.

Total Electric Cost is calculated as the sum of the previous three numbers

Current Energy Status – Space Heating (Estimated)

2000 Census Data is from the Community and Regional Affairs database; and is most helpful in indicating which communities use wood for heat. Some communities which may have large hydro plants nearby may use electric heat, but these communities typically are not PCE communities, as this program is specifically designed for those depending on diesel power generation.

2008 Estimated Heating Fuel Use is a community-wide estimate of the total gallons of fuel used for heating calculated by ISER, based on several variables including population, number of households, square footage per household, and heating degree days. The sample size for this estimate is small, and the regression is less robust than desired. Improving this estimate is a goal of ISER's energy information data network.

Estimate Heating Fuel Cost per Gallon is calculated as the *Estimated Local Fuel Cost at $110/bbl* plus $1.00 per gallon. Reports from many villages (especially AVEC villages) indicate that heating fuel prices are far higher than this measure would indicate.

$/MMBtu Delivered to User is based on the Estimated Heating Fuel Cost per gallon times 9.05. This factor comes from taking 1 million Btus divided by the lower heating value of a gallon of heating fuel (130,000 Btu/Gallon) times an efficiency of 85% for a heating oil appliance. The equivalent cost for Anchorage natural gas users is currently about $9.56 per MMBtu delivered.

Total Heating Oil figure is the *Estimated Heating Fuel Cost per Gallon* times the *2008 Estimated Heating Fuel Use.*

Current Cost of Energy – Transportation Cost (Estimated)

Estimated Diesel is an extrapolated number from a previous ISER model. This model, not considered robust, should be used with caution. Also please note that this number does not include gasoline used for motor fuels. However, this represents the best available estimate at the current time.

Estimated Cost is based on a retail markup of $1 per gallon over the cost of fuel delivered to the utility for power generation. This is identical to the estimate for that of heating fuel, but it is well below the current cost of transportation fuels in some villages.

Total Transportation cost is the product of the two numbers above.

Energy Total is the sum of the electrical, heating, and transportation costs for the entire village.

Possible Upgrades to Existing Diesel Plant (estimate)

Many power plants are due for upgrades, some for safety reasons, some for efficiency reasons. This section estimates the cost of those upgrades, and the impact on the cost of power if the expense is born by the consumer.

Upgrade Needed is the level of improvement that needs to be made to the power plant. This can range from a complete power plant replacement ($3,000,000), powerhouse module upgrade

($1,350,000), powerhouse upgrade ($1,000,000), switch gear upgrade ($600,000), or generator upgrade ($150,000). Note that these estimates are fixed, and do not depend on the size of the village or the size of the power plant.

Status is the place this project is in the statewide list for these projects.

Achievable Efficiency is an estimate of what a well-managed power plant of this size: 14 kW-hours per gallon of diesel fuel for plants under 400 kW, and 14.75 kW-hours per gallon for plants over this size.

Fuel Use is the new, calculated fuel consumption with the more efficient power plant, assuming the efficiency above is reached.

Estimated Cost is an estimate on how much the upgrade will cost. This is based only on the upgrade level, as listed above.

Annual Capital Cost is based on the estimated cost amortized at 3% over 15 years.

New Fuel Cost is the Fuel Use times the estimated local fuel cost at $110 per barrel.

New Electrical Cost is the cost of electricity after the upgrade. This may or may not be cheaper than the existing cost of power.

Savings is an estimate of how much money this upgrade will save the community, although this savings may be negative. However, many power plant upgrades must be undertaken for environment, safety, or other reasons. The savings might not be the reason for the upgrade.

Diesel Engine Heat Recovery

Given the higher cost of fuel in recent years, one way to save fuel at a community level is to recover as much heat as possible from the diesel generator plant. Many communities have already installed this equipment, although some of these installations are no longer operable. This section summarizes the economics of this energy source.

Heat Recovery Installed indicates communities where heat recovery systems are known to be installed. A blank indicates that there is no record of a heat recovery installation in this community.

Is It Working Now indicates the current state of operation of the heat recovery system. 'Yes' indicates that the system is working; 'No' indicates that the system is not currently working. If the heat recovery system is working, the savings indicated in the following fields have already been realized. However, the reporting on these heat recovery systems is sketchy, but this sectionis included to emphasize the importance of keeping these systems operational.

BLDGs Connected and Working indicates which buildings are currently receiving heat from the heat recovery system.

Water Jacket indicates the total amount of heat that could be collected from the water jacket of the diesel engines, given in gallons of fuel equivalent. This number is 15% of the total gallons of fuel consumed by the diesel generator.

Value is an estimate of the value of the heat if it can be used to replace diesel fuel, at local prices for heating fuel. Note that in almost all cases, not all of the recovered heat can be used (like heat in the summer), but given the general need for heat for much of the year in most places in Alaska, recovery of most of this heat is possible.

Stack Heat refers to energy that can be recovered from the exhaust stack of the diesel generators. In the past, attempts to recover heat from this source proved problematic, due to soot accumulation and corrosion. Newer engines produce less soot and newer fuels have much less sulfur, so these systems are now proving feasible, as long as enough heat is left in the exhaust stream to prevent condensation in the stack. These systems are currently recommended only for generators larger than 400 kW and for villages of more than 700 people. When these criteria are met, an estimated 10% of the fuel value used by the engine can be recovered.

Installed cost is estimated based on $2800 times the average power output of the plant, based on installation costs from the state.

Annual I&D costs are calculated at 3% interest and 15 years.

Savings are the estimated savings to the community on heating costs. Please note that in communities where heat recovery is already being done, these savings have already been realized, but these savings are not included in the community heating fuel estimates, so they are listed here.

Alternative Technologies

This section lists the alternative technologies available to local communities. Several fields are included for each technology, and some are specific to a given technology.

The first technologies that are listed are commercial or near commercial technologies, where estimates have been made of the approximate cost of installing these technologies in a given village. These technologies are conventional hydro, wind, geothermal, and biomass.

The common fields include the top row:

Installed kW indicates the total installed capacity of the alternative technology. Some alternative projects are defined by the size of the resource (such as geothermal or hydro) while others are defined by the size of the generators selected to match the peak load of the community (wind and biomass).

kW-hours Per Year is an estimate of the total power production of the alternative on an annual basis.

Annual Electric is the *kW-hours per year* divided by the *Average kilowatt Hours Sold* from PCE, and is reported as a percentage. This number may be less than 100%, indicating that the installed project cannot meet all of the community power demand, or it may be greater than 100%, indicating that the available power is more than the community currently uses on an annual basis. However, intermittent resources such as wind do not necessarily match the load profile of the community, and modeling is necessary to determine the precise amount of energy that can be used to displace the current diesel load. In this case, this number is simply included to provide a sense of how big the project is compared to the local market. In both wind and hydro, models estimated how much diesel generated power could be displaced. That number is given here. Excess power may be converted to heat, but that energy is not included in calculations.

Other common fields are the economic numbers in the middle column:

Capital Cost is an estimate of the installed cost of the project in the community. These numbers are based on statewide estimates, old engineering studies, or engineering estimates, and are included to provide a rough calculation of the cost of this project in this community. No projects will be funded based on this number; an engineering feasibility study is required.

Annual Capital Cost is based on the capital cost above, using a 3% interest rate and a 20-year payback period, except for hydro, where a 50-year payback is used. The cost per kilowatt hour is also calculated.

Annual O&M is the estimated Operations and Maintenance costs for the technology, usually based on a percentage of the installed capital costs. The cost per kilowatt hour is also calculated.

Fuel Costs are the anticipated annual fuel costs for the alternative energy source. Biomass is the only alternative that has a fuel cost in the current model. The cost per kilowatt hour is also calculated.

Total Annual Cost is the sum of the Capital, O&M, and Fuel costs above. The cost per kilowatt hour is also calculated. This cost does not include the non-fuel costs, or the balance of diesel power that might still be needed to provide energy to the community.

New Community COE is the new cost of electricity based on adding this resource to the mix. This number includes the non-fuel costs (the costs of operating the utility) and the cost of operating the diesel plant for power when the alternative is not available. There are two cases that must be discussed: (1) when the total kW-hours/year is less than the total electrical demand for the community, and (2) when the total kW-hours per year is above the total village electrical demand.

For Case (1), the assumption made in this calculation is that all electrical power can be used to displace diesel up to the annual power consumption of the village, which is not likely to be true for technologies like wind. The New Community COE is calculated as the cost of the new alternative, times the amount of power it provides, plus the cost of generating diesel power for the balance, plus the non-fuel costs.

For Case (2), the cost of electricity is calculated as the total annual costs of the alternative source, plus the non-fuel costs, divided by total kilo-Watt hours sold in the community. For large-scale geothermal or hydro projects, this may result in a high cost of electricity even though the cost per kW-hr above might be low, as the cost of developing the resource must be paid from a small local base.

Savings is calculated as the difference between the current cost of producing electricity, minus the cost of producing electricity with the alternative. In some case, this is a positive number (the new technology is more cost effective), while in others it is negative (the new technology is less cost effective than the existing power plant).

Wood

Wood is an abundant fuel in some parts of the state, but nearly absent in others. Today, almost all wood used is for space heat, not for electrical power generation. New power generators are being developed that might allow for electrical power to be generated from wood or other biomass, and the cost of electricity from these systems was modeled in a paper by Crimp, Strandberg, and Colt in 2007. The cost estimates given in this report for electrical power generation are from that report. For this calculation, a cost of $225 per cord was assumed for all communities, although some might have fuel available for considerably less cost. These wood generators will also produce significant amounts of heat, but this value is not included in the calculation.

Wind-Diesel Hybrids

Unlike wind power in grid connected areas where wind contributes only a small amount of the total needed power, small Alaskan communities with wind turbines would like to replace a significant amount of their total village power needs with wind. This means that all wind systems are high penetration, and care must be taken with the integration of the wind with the diesel plant.

The Wind Class and wind speed numbers indicate the size of the resource in the community. Small communities of class 5 and above and larger communities of class 4 and above are included in this study. The installed kW is based on the peak load of the community. Modeling with HOMER was done for most of the small communities, and is the basis of the economic calculations, but it should be stressed that the economic analysis here is very simplistic, and should be used only for a screening analysis.

Hydro

The projects described in this section are all conventional hydro projects, not run-of-the-river hydrokinetic projects (these are still too new for accurate economic estimates to be calculated). Many of these hydro sites have been identified over the past decades, and some of them have been studied quite extensively. The data in this section is by far the most complete of any of the alternative electrical systems.

The Installed kW and the kilowatt-hours per year numbers are estimated based on flow data from the streams, but the reliability of the information depends on the level of study completed. The site name is the location of the project. The plant factor (how much of the year the stream can produce power), penetration factor (how much of the existing load could be replaced given the plant factor), and % community energy (a simple comparison of kW-hours generated per year to kW-hours sold under PCE) are all attempts to estimate how much of the existing energy base might be displaced by the installed hydro project.

Some hydro projects are quite large, and might indicate potential for power to be used for other applications.

Geothermal

Alaska has many potential geothermal sites, but few of these are located close enough to large power markets to justify their development. Development of a geothermal power system requires significant investment during the exploration phase, so much of the costs of the project are incurred before the ultimate economic viability can be determined. Most of the geothermal projects described here have both a shallow resource estimate and a deep resource estimate.

Biomass For Heat

Recent development of high efficiency wood stoves using a gasification design allow for clean burning of cordwood. These are most commonly refered to as Garn stoves, but other manufactures are marketing similar designs. Most communities have some form of biomass that could be used to fuel these stoves, but their size requires a fairly large heat load (community buildings, schools, or multiple residences) in close proximity to justify their installation. If these criteria can be met and fuel can be obtained, significant savings can be attained.

Other Resources

There are several other potential resources for remote communities, including wave, tidal, coal, coal bed methane, and natural gas. No economic analysis has been done for any of these resources due to lack of reliable cost information, but these resources are listed as potential sources for future development.

Renewable Energy Fund Applications

This section briefly lists the applications submitted to the Alaska Rewable energy fund.

Glossary

Absorption Chiller - A device that uses heat energy rather than mechanical energy to cool an interior space through the evaporation of a volatile fluid.

Active Solar - A solar water or spaceheating system that uses pumps or fans to circulate the fluid (water or heat transfer fluid like diluted antifreeze) from the solar collectors to a storage tank subsystem.

Alternative Fuels - A term for "nonconventional" transportation fuels derived from natural gas (propane, compressed natural gas, methanol, etc.) or biomass materials (ethanol, methanol, or biodiesel).

Anemometer - An instrument for measuring the velocity of wind; a wind gauge.

Availability - Describes the reliability of power plants. It refers to the number of hours that a power plant is available to produce power divided by the total hours in a set time period, usually a year.

Avoided Cost - The incremental cost to an electric power producer to generate or purchase a unit of electricity or capacity or both.

Biodiesel - A domestic, renewable fuel for diesel engines derived from natural oils like fish and vegetable oil; produced by a chemical process that removes the glycerin from the oil and meets a national specification (ASTM D 6751).

Biomass - Organic matter that is available on a renewable basis, including agricultural crops and agricultural wastes and residues, wood and wood wastes and residues, animal wastes, municipal wastes, and aquatic plants.

Bioenergy - Electrical, mechanical, or thermal energy or fuels derived from biomass.

Capacity Factor - The ratio of the average power output of a generating unit to the capacity rating of the unit over a specified period of time, usually a year.

Co-firing - Using more than one fuel source to produce electricity in a power plant. Common combinations include biomass and coal, biomass and natural gas, or natural gas and coal.

Cogeneration - The generation of electricity and the concurrent use of rejected thermal energy from the conversion system as an auxiliary energy source.

Conduction - The transfer of heat through a material by the transfer of kinetic energy from particle to particle; the flow of heat between two materials of different temperatures that are in direct physical contact.

Convection - The transfer of heat by means of air currents.

Dam - A structure for impeding and controlling the flow of water in a water course, it increases the water elevation to create hydraulic head. The reservoir creates, in effect, stored energy.

District Heating System - Local system that provides thermal energy through steam or hot water piped to buildings within a specific geographic area. Used for space heating, water heating, cooling, and industrial processes. A common application of geothermal resources.

Distributed Generation - Localized or on-site power generation, which can be used to reduce the burden on a transmission system by generating electricity close to areas of customer need.

Distribution Line - One or more circuits of an electrical distribution system on the same line or poles or supporting structures, usually operating at a lower voltage relative to a transmission line.

Domestic Hot Water - Water heated for residential washing, bathing, etc.

Electrical Energy - The amount of work accomplished by electrical power, usually measured in kilowatt-hours (kWh). One kWh is 1,000 Watts generated for one hour and is equal to 3,413Btu.

Energy - The capability of doing work; different forms of energy can be converted to other forms, but the total amount of energy remains the same.

Energy Crop - A plant grown specifically for use in biomass electricity or thermal generation.

Energy Storage - The process of storing or converting energy from one form to another for later use. Storage devices and systems include batteries, conventional and pumped storage hydroelectric, flywheels, compressed gas, hydrogen, and thermal mass.

Ethanol - A colorless liquid that is the product of fermentation used in alcoholic beverages, in industrial processes, and as a fuel.

Feedstock - A raw material that can be converted to one or more products.

Fossil Fuels - Fuels including oil, natural gas, and coal formed in the ground from the remains of dead plants and animals. It takes millions of years to form fossil fuels.

Fuel - Any material that can be burned to make energy.

Fuel Oil - Any liquid petroleum product burned for the generation of heat in a furnace or firebox or for the generation of power in an engine. Domestic (residential) heating fuels are classed as Nos. 1, 2, 3; Industrial fuels as Nos. 4, 5, and 6.

Generator - A device for converting mechanical energy to electrical energy.

Geothermal Energy - Energy produced by the internal heat of the earth; geothermal heat sources include: hydrothermal convective systems; pressurized water reservoirs; hot dry rocks; manual gradients; and magma. Geothermal energy can be used directly for heating and cooling or to produce electric power.

Head - A measure of fluid pressure, commonly used in water pumping and hydro power to express height that a pump must lift water, or the distance water falls. Total head accounts for friction and other head losses.

Glossary

Heat Pump - An electricity powered device that extracts available heat from one area (the heat source) and transfers it to another (the heat sink) to either heat or cool an interior space or to extract heat energy from a fluid.

Hybrid System - An energy system that includes two different types of technologies that produce the same type of energy; for example, a wind turbine and a solar photovoltaic array combined to meet electric power demand.

Hydroelectric Power Plant - A power plant that produces electricity by the force of water falling through a hydro turbine that spins a generator.

Hydrogen - A chemical element (H2) that can be used as a fuel since it has a very high energy content.

Landfill Gas - Produced in landfills, naturally occurring methane that can be burned in a boiler to produce heat or in a gas turbine or engine-generator to produce electricity.

Large-scale or Utility-scale - A power generating facility designed to output enough electricity for purchase by a utility.

Load - Amount of electricity required to meet customer demand at any given time.

Meteorological (Met) Tower - A structure instrumented with anemometers, wind vanes, and other sensors to measure the wind resource at a site.

Ocean Energy Systems - Energy conversion technologies that harness the energy in tides, waves, and thermal gradients in the oceans.

Ocean Thermal Energy Conversion (OTEC) - The process or technologies for producing energy by harnessing the temperature differences between ocean surface waters and that of ocean depths.

Organic Rankine Cycle - A system that uses a hydrocarbon instead of water as a working fluid to spin a turbine, and therefore can operate at lower temperatures and pressures than a conventional steam process.

Panel (Solar) - A term generally applied to individual solar collectors, and typically to solar photovoltaic collectors or modules.

Passive Solar Design - Construction of a building to maximize solar heat gain in the winter and minimize it in the summer, thereby reducing the use of mechanical heating and cooling systems.

Peak Load – The amount of electricity required to meet customer demand at its highest.

Penstock - A component of a hydropower plant; a pipe that delivers water to the turbine.

Photovoltaics (PV) - Devices that convert sunlight directly into electricity by using semiconductor materials. Most commonly found on a fixed or movable panel; also called solar panels.

Power - Energy that is capable of doing work; the time rate at which work is performed, measured in horsepower, Watts, or Btu per hour.

Production Tax Credit (PTC) – An incentive that allows the owner of a qualifying energy project to reduce his taxes by a specified amount. The federal PTC for wind, geothermal, and closed-loop biomass is 1.9 cents per kWh.

Radiation - The transfer of heat through matter or space by means of electromagnetic waves.

Railbelt - The portion of Alaska that is near the Alaska Railroad, generally including Fairbanks, Anchorage, and the Kenai Peninsula.

Renewable Resource - Energy sources that are continuously replenished by natural processes, such as wind, solar, biomass, hydroelectric, wave, tidal, and geothermal.

Run-of-River Hydroelectric – A type of hydroelectric facility that uses the river flow with very little alteration and little or no impoundment of the water.

Small-scale or Residential-scale - A generating facility designed to output enough electricity, generally 250 kW or smaller. to offset the needs of a residence, farm, or small group of farms.

Solar Energy - Electromagnetic energy transmitted from the sun (solar radiation).

Solar Radiation - A general term for the visible and near visible (ultraviolet and near-infrared) electromagnetic radiation that is emitted by the sun. It has a spectral, or wavelength, distribution that corresponds to different energy levels; short wavelength radiation has a higher energy than long-wavelength radiation.

Tidal Power - The power available from either the rise and fall or flow associated with ocean tides.

Transmission Grid - The network of power lines and associated equipment required to deliver electricity from generating facilities to consumers.

Turbine - A device for converting the flow of a fluid (air, steam, water, or hot gases) into mechanical motion.

Wave Energy - Energy derived from the motion of ocean waves.

Wind Energy - Energy derived from the movement of the wind across a landscape. Wind is caused by the sun heating the atmosphere, earth, and oceans.

Wind Turbine - A device typically having two or three blades, that converts energy in the wind to electrical energy.

Windmill - A device that converts energy in the wind to mechanical energy that is used to grind grain or pump water.

Wind Power Class - A class based on wind power density ranging from 1 (worst) to 7 (best).

Wind Power Density - The amount of power per unit area of a free windstream.

Wind Resource Assessment - The process of characterizing the wind resource and its energy potential for a specific site or geographical area.

Units of Measure

Ampere - A unit of measure for an electrical current; the amount of current that flows in a circuit at an electromotive force of one Volt and at a resistance of one Ohm. Abbreviated as amp.

Amp-Hour - A measure of the flow of current (in amperes) over one hour.

Barrel (Petroleum) - Equivalent to 42 U.S. gallons (306 pounds of oil, or 5.78 million Btu).

British Thermal Unit (Btu) - The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit; equal to 252 calories.

Cord (of Wood) - A stack of wood 4 feet by 4 feet by 8 feet.

Gigawatt (GW) - A unit of power equal to 1 billion Watts; 1 million kilowatts, or 1,000 megawatts.

Hertz - A measure of the number of cycles or wavelengths of electrical energy per second; U.S. electricity supply has a standard frequency of 60 hertz.

Horsepower (hp) - A measure of time rate of mechanical energy output; usually applied to electric motors as the maximum output; 1 electrical hp is equal to 0.746 kilowatts or 2,545 Btu per hour.

Kilowatt (kW) - A standard unit of electrical power equal to one thousand watts, or to the energy consumption at a rate of 1000 Joules per second.

Kilowatt-hour (kWh) - A common measurement of electricity equivalent to one kilowatt of power generated or consumed over the period of one hour; equivalent to 3,413 Btu.

Megawatt (MW) - One thousand kilowatts, or 1 million watts; standard measure of electric power plant generating capacity.

Megawatt-hour (MWh) - One thousand kilowatt-hours or 1 million watt-hours.

Mill - A common monetary measure equal to one-thousandth of a dollar or a tenth of a cent.

MMTCO2e - million metric tons carbon dioxide equivalent

Quad - One quadrillion Btu (1,000,000,000,000,000 Btu)

Therm - A unit of heat containing 100,000 British thermal units (Btu).

Terawatt (TW) - A unit of electrical power equal to one trillion watts or one million megawatts.

Tonne - A unit of mass equal to 1,000 kilograms or 2,204.6 pounds, also known as a metric ton.

Volt (V) - A unit of electrical force equal to that amount of electromotive force that will cause a steady current of one ampere to flow through a resistance of one ohm.

Voltage - The amount of electromotive force, measured in volts, that exists between two points.

Watt (W) - Instantaneous measure of power, equivalent to one ampere under an electrical pressure of one volt. One watt equals 1/746 horsepower, or one joule per second. It is the product of Voltage and Current (amperage).

Watt-Hour - A unit of electricity consumption of one Watt over the period of one hour.

Watts per Square Meter (W/m_2) – Unit used to measure wind power density, measured in Watts per square meter of blade swept area.

Acronyms - List of Organizations

ACEP	Alaska Center for Energy and Power
AEA	Alaska Energy Authority
AETDL	Arctic Energy Technology Development Laboratory
AHFC	Alaska Housing and Finance Corpora¬tion
AIDEA	Alaska Industrial Development & Export Authority
ANGDA	Alaska Natural Gas Development Authority
ANGTL	Alaska Natural Gas to Liquids
APA	Alaska Power Association
AP&T	Alaska Power & Telephone Inc.
ASTM	American Society of Testing Materials
AVEC	Alaska Village Electric Cooperative
AWEDTG	Alaska Wood Energy Development Task Group
BLM	Bureau of Land Management
CCCF	Cen¬ter for Climate Change and Forecasting
CCHRC	Cold Climate Housing Research Center
CEA	Chugach Electric Association
DCCED	Department of Commerce, Community and Economic Development
DEC	Department of Environmental Conservation
DHSS	Department of Health and Social Services
DOE	Department of Energy
DNR	Department of Natural Resources
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FEDC	Fairbanks Economic Development Corporation
FERC	Federal Energy Regulatory Commission
GVEA	Golden Valley Electric Association
HEA	Homer Electric Association
IAEA	International Atomic Energy Agency
IEC	International Electro-Technical Commission
ISER	Institute of Social and Economic Research
KEA	Kodiak Electric Association
MEA	Matanuska Electric Association
ML&P	Anchorage Municipal Light & Power
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
OPEC	Organization of Petroleum Exporting Countries
ORPC	Ocean Renewable Power Company
RCA	Regulatory Commission of Alaska
REAP	Renewable Energy Alaska Project
REGA	Railbelt Electrical Grid Authority
SES	Seward Electric System
UAF	University of Alaska, Fairbanks
UEK	Underwater Electric Kite Corporation
USDOE	US Department of Energy
UTC	United Technology Corporation

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