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HOUSE COMMITTEE REPORT

(11)

Date Referred to Committee: February 11, 2008 FURTHER REFERRALS:

Date of Committee Action: 3/25/08

The FINANCE Committee considered: HB 336

HOUSE BILL NO. 336 SUSITNA HYDROELECTRIC PROJECT

"An Act directing the Alaska Energy Authority to conduct a study of and to prepare a proposal for an appropriately sized Susitna River hydroelectric power project; and providing for an effective date."

Recommends it be replaced with [ ] HCS or [✓] CS for HB 336 (RCS)

For Senate Bills with new title: [ ] Technical Title [ ] New Title: HCR [X] Same Title [ ] New Title

[ ] attach amendments

[ ] add new referral to ________ Committee

[ ] Letter of Intent ________ Committee

List of Abbrev for Depts.: ADM CED COR CRT EED DEC DFG GOV HSS LWF LAW LEG MVA DNR DPS REV DOT UA

***NEW* FISCAL NOTES** *Assigned by Chief Clerk's Office

List by Dept(s):	*FN#	Fiscal	Indet.	Zero
HFC		✓		

***PREVIOUS* FISCAL NOTES**

List by Dept(s):	FN#	Fiscal	Indet.	Zero

Signing with recommendations	Printed Last Name	DP	DNP	NR	AM
Mike Kelly	KELLY	X			
Bill Thomas	Thomas	✓			
[signature]	Joule			X	
Bill Stoltze	STOLTZE	X			
Chair: Mike Chenault	Chenault	X			
Chair: K Meyer	Meyer	X			

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CS HB 336 (RES)
() Publish Date:

Identifier (file name):
Dept. Affected: DCCED

Title	AEA study and proposal of Susitna River hydroelectric power project	RDU	Alaska Energy Authority (453)
		Component	Statewide Project Development
Sponsor	Rep. Johnson		
Requester	House Finance Committee	Component Number	2888

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING							
CAPITAL EXPENDITURES	1,000.0		0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ( )							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
1012 Rail Enrgy	1,000.0						
TOTAL	1,000.0		0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2008) cost:

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This legislation requires the Alaska Energy Authority (AEA) to conduct a study and prepare a proposal for a hydroelectric power project on the Susitna River appropriately sized for the Railbelt Area.

The project would be significant in scope and would likely extend beyone one year; therefore, a capital appropriation is suggested. It is likely additional funds would be required, but these amounts are indeterminate at this time. It is assumed that AEA would develop a best fit scenario, and develop a preliminary design to provide enough detail that a valid project concept estimate and schedule could be developed and reported to the Legislature no later than June 30, 2010.

The fund source indicated in this fiscal note for the capital expenditure is the Rail Belt Energy Fund.

Prepared by: House Finance Committee — Phone 465-6875
Division — Date/Time 3/25/08 11:38 a.m.
Approved by: Rep. Kevin Meyer, Co-Chairman — Date 3/25/2008
Rep. Mike Chenault, Co-Chairman

(Revised 11/1/2007 OMB)

FISCAL NOTE

Replaced

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number:
Bill Version: CS HB 336 (RES)
() Publish Date:

Identifier (file name):
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CHANGE IN REVENUES ( )							

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Approved by: Rep. Kevin Meyer, Co-Chairman — Date 3/25/2008
Rep. Mike Chenault, Co-Chairman

ALASKA STATE LEGISLATURE

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Session:
State Capitol, Room 126
Juneau, Alaska
99801-1182
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REPRESENTATIVE CRAIG JOHNSON
HOUSE DISTRICT 28

Sponsor Statement
Susitna River Hydroelectric Power Project
HB 336

This legislation will direct the Alaska Energy Authority to conduct a review of the past studies and analyses of the Susitna River hydroelectric power project. Submittal of its report to the legislature would be no later than June 30, 2010.

Additionally, under this legislation, Alaska Energy Authority a will conduct a collaborative study with Railbelt utilities to propose an appropriately-sized hydroelectric power project on the Susitna River.

Low price of oil helped to end the Susitna hydropower plan in the mid 1980's. The high price of oil could open the window of opportunity for development today. This proposal would respond to the assessed needs for power expansion to Kodiak, Southwest, and Northern Alaska.

The Act is scheduled for termination June 30, 2010.

ALASKA STATE LEGISLATURE

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REPRESENTATIVE CRAIG JOHNSON
HOUSE DISTRICT 28

MEMORANDUM

TO: Members, House Finance Committee

FROM: Representative Craig Johnson

DATE: February 12, 2008

SUBJECT: Changes between HB 336 & CSHB 336 (RES)

Page 1, line 11,
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The authority shall present an interim report to the legislature not later than February 15, 2009. If, at any point in the work process before the interim report is due, the authority finds that the project is nonviable, work shall be halted, and a report with those findings shall be immediately submitted to the legislature. Unless the authority finds, before the interim report is due, that the project is nonviable,

Page 1 line 11,
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Supplement to Fiscal Note for House Bill 336 – Susitna Dam Estimate

At the request of the House Finance Committee, the following note has been developed to provide additional back up to the rough order of magnitude estimate for Task 1 on the Feasibility Study Plan for House Bill No. 336 "directing the Alaska Energy Authority to conduct a study of and to prepare a proposal for an appropriately sized Susitna River hydroelectric power plant".

In that study plan, Work Task 1 is to provide a feasibility study and estimate of plant and of generated power costs based on reviewing and updating previous engineering work most specifically the work contracted by the Alaska Power Authority in support of the application for a Federal Energy Regulatory Commission (FERC) license to construct the dam in 1984.

An engineering design contractor and environmental consultant will be selected from AEA's approved list of term contracts. A scope of work and estimate will be requested for the scope statement for Work Task 1. It is anticipated that the scope of work provided will be consistent with the description below.

Work Task 1 consists of the following activities.

1. Collection, review and organization of existing engineering documentation from the Acres American study as well as any appropriate U.S. Army Corps of Engineers documentation. A gap analysis of the material will be provided to identify where more detailed engineering may be required.
   Cost: $100,000

2. Engineering evaluation of existing design, update engineering work to current codes and standards including seismic codes, determination of possible options for generation capacity appropriate for the Susitna location within the context of the 1984 design, preliminary review of appropriateness of original environmental work, order of magnitude engineering of Alaska intertie, order of magnitude scheduling and constructability for each generation case. All work to be performed by senior engineering consultants.
   Cost: $500,000

3. Development of risk analysis on each case, including areas where additional engineering will be required, additional permitting, constructability and performance of each of the generation cases.
   Cost: $50,000

4. Peer review of engineering both internally and in the Alaskan community to assist in determination of any fatal flaws in the possible designs or configurations.
   Cost: $50,000

5. Cost estimates for each potential case, determination of rough funding options and costs of money and estimate of costs of power. Evaluate against existing power costs and against existing power costs with fuel escalation.
   Cost: $200,000

6. Development of final report and presentation
   Cost: $50,000

7. Travel for consulting engineers to Alaska
   Cost: $50,000

Total Cost: $1,000,000

by AEA 3/5/08

Estimate for Susitna Hydro-electric Feasibility Study

In response to House Bill No. 336 "directing the Alaska Energy Authority to conduct a study of and to prepare a proposal for an appropriately sized Susitna River hydroelectric power plant" this estimate and scope of work has been prepared.

The Susitna Hydro project has been subject to over 60 years of study and analysis, culminating in a $135 million dollar engineering study and application to the Federal Energy Regulatory Commission (FERC) for a license to construct in 1984. At that time the project was estimated to cost $5.3 billion for 1,620 MW of generation capacity. Concerns about the ability to finance this project in conjunction with the collapse of crude oil pricing resulted in the termination of this project.

Higher fuel costs, potentially dwindling natural gas resources, more stringent environmental restrictions including mercury and carbon emissions, and an energy infrastructure that is reaching the end of service life require a review of potential energy projects of which the Susitna Hydro project is one important candidate.

One key concern of the existing Susitna design is that the generation capacity of 1,620 MW far exceeds the current size of the Railbelt grid (approximately 1,000 MW) which results in significant concerns on load balancing and reliability.

Objectives

The objective of this study is update previous study estimates to determine if the Susitna Hydro project is a feasible alternate generation source for the Railbelt Electrical Grid. To support this objective estimates will have to be made on potential sizing options (and costs) as well as reviewing environmental and socio-economic impacts. To aid in decision making cost of power for generic alternative generation sources (coal, gas, wind, geothermal) will be developed, and finance options will considered.

Assumptions

The cost estimates for this work and the scope of work to evaluate the Susitna project are based on the following three assumptions.

First, the estimates and information that will be generated are for the purpose of understanding the feasibility of this potential energy generation source, they will answer the question – is the cost of power from this source competitive with other energy sources and should we proceed to more detailed analysis? The accuracy of the study estimates should not be considered to be better than (+/-) 30%.

Secondly, it is important to understand that this is only one potential option in an Alaskan Energy Portfolio. A separate strategic energy plan for the State is necessary to be able to put these options into perspective. For example, for a project of this magnitude it is important that an appropriate industrial energy load anchor the demand. While examples of potential demands will be used in this

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study, no significant analysis of those demands will be done. In a similar fashion the cost of upgrading the Railbelt Interties is not included in this study as those upgrades will be required for any significant change in Railbelt generation.

Third, to minimize a long lead time that an RFP would require, AEA will be using a qualified engineering design contractor and environmental consultant from the qualified list of term contracts. Requests will be made of three contractors to provide assurance that scope of work and estimates are appropriate.

Work Tasks and Estimates

The following work tasks and goals are envisioned to complete the study objectives. They are organized in order of priority and in doing so allow a phased approach to be taken on this study. If at any point in the work process it would appear that the project is non-viable, work will be halted and a summary completed.

Work Task 1: Feasibility study and estimate of plant and of generated power costs

The 1984 estimates for construction of the Susitna Hydro project will be updated for current costs as well as current construction and design technology. Constructability and logistics will be key components of this update. Additionally a review of engineering and technical risks including seismic design will be identified. The design of this power is such that there are minimal size reductions that can be done. While there may be a need for 700 MW of generating capacity the constraints of the Susitna site may allow for options of 300 MW, and a 1000 MW. The study therefore will examine the possible size options that are inherent in the 1984 estimate and provide capital costs and costs of power over the lifetime of the facility for those options.

Estimated Cost: $1,000,000

Work Task 2: Environmental/Socio-economic Impact Study

Environmental permitting and the socio-economic impact on the affected area is a key component of this study and will have the most impact on the feasibility of this study. A review of necessary permits and an analysis of potential impacts to the area will be done.

Estimated Cost: $500,000

Work Task 3: Cost of Power for Selected Alternatives

An estimate of approximate costs of alternative power generation that would be accessible to the Railbelt will be made. Options will consider the appropriate use of coal, natural gas, wind, geothermal, tidal and an alternate source of hydro. These estimates will be used to compare the reasonability of power generation from Susitna.

Estimated Cost: $800,000

Work Task 4: Financing Options

The size of this single generation will be in excess of $5 billion and while it may provide appropriately cost of power, the ability to finance the costs may be the limiting factor. An analysis of potential financing options will be developed.

Estimated Cost: $200,000

Field Work

Limited field work is envisioned; however there may be need for helicopter access to the location of the proposed dam sites as well as limited amount of field work including terrain, river conditions and potential construction camp sites and lay down areas.

Estimated Cost: $250,000

Total Estimated Study Cost: $2,750,000

<u>Schedule</u>

It is anticipated that this work will take approximately two years. Over the course of the project interim reports and decisions on whether to proceed will be issued.

July 2008: Start of Project

December 2009: Completion of Estimates and Hydro generation options:

February 2010: Draft Final Report:

Susitna

My name is Eric Marchegiani. I am first and foremost a citizen of Alaska and a resident of this wonderful State since May of 1975. I am also a member of the Matanuska Electric Association (MEA) Cooperative since I reside in Chugiak, Ak. I initially was employed with the Corp of Engineers on Elmendorf AFB from May 1975 until August 1981 and I completed investigations of hydroelectric power in SE Alaska, Railbelt and other parts of the State. I became a registered professional engineer in the State of Ak and four other states in the late 1970s. I worked for the State of Alaska, Alaska Power Authority from August 1981 to December of 2000.

During that timeframe I worked on a number of different projects for the Alaska Power Authority and its successor the Alaska Energy Authority. One of my duties were to provide oversight to the environmental studies that were incorporated into the FERC License application for the Susitna Project. I was not involved in all of the engineering aspects of the project but was peripherally involved in that those aspects that would affect the flows and the impacts or mitigation for the fishery resource which was one of the primary concerns environmentally. I provided oversight and management during the stage whereby we were closing the project up and organizing the reports and documents to be saved and stored for future use. I am not an expert on any certain aspect of the Project but rather I have a historic perspective on the overall project.

Recently there has been renewed interest in the Susitna Hydroelectric Project and questions have been raised concerning the project along with new legislation to "dust" off the reports and see if it makes sense to open up the option of pursuing the project again. Some of what follows are questions that I have heard raised and others that one might ask about the project.

Please note the following is my personal opinion only and has no bearing or reflection of my present employment with the Federal Government!

Questions:

1. **Why was the project not pursued to completion back in the early to mid 1980s? A number of reasons have been purported but the primary reason was that at the time that the FERC license was being submitted and responses being generated on the EIS for the project; the price of oil dropped down to something in the range of $9/ barrel.** The initial economics of the project were based upon $20 to $25/ barrel and the idea was that oil was suppose to escalate over a period of time to may be $30 per barrel. No one at the timeframe could imagine $30/barrel oil; little did they thing that in 2008 we would see it at $100 per barrel. The economy was in poor shape and a large number of people were turning in their keys to their homes and just leaving the state. For those of you that were here; you may have remembered the depression that occurred from about 1985 thru about 1990 before things began to look a bit better.
2. **One of the other reasons was the huge impact created by the statement from the bond counsel; which indicated that the Permanent Fund earnings (not the fund itself) would need to be pledged to cover any default of the bonds.** In essence, if the State was not able to make the payments on the bonds for whatever reason, then the interest earnings would need to be utilized to make the payments. Because the Fund is so politically charged and the general public's opinion that would weigh in on the issue it was felt that it would likely be impossible to complete the financing of the project with that condition. Would that be necessary today... I have no idea; this is one more aspect that the update should address.

(From Bill STOLTZE)

3. **On the environmental side there were a number of concerns** but in my mind at least, it did not seem like there should be all that big of a challenge. Although there may have been some environmental concerns, I believe that was sort of a smoke screen for a larger concern that the project would be oversized and would generate so low of a cost for power that aluminum smelters would be brought in to suck up the excess energy. In my opinion, this concern was not really based upon any solid information. The cost of power from the project depending upon the financing would have been in the $0.04/ kWh to may be $0.05/kWh range. This is about double and possibly triple what the pacific northwest was generating electricity for and one would not have to ship the ore to Alaska to process it. It just does not make a lot of sense to use $0.06/ kWh energy when you might have access o $0.02/kwh.
4. **On the question about the project being too big for the Railbelt load**. If the total project was completed and running, it could provide 1,600 Mw of peak power(short term) or approximately 800 Mw of base load power(long term). The amount of energy that it could produce is about 6,500,000 Mwh of electricity each year. The combined sales (actual generation energy requirements would be larger) by the six Railbelt utilities in 2006 was about 5,000,000 Mwh(Based upon data from 2006 CEA Annual Report) or about 77% of the possible output of the project. If the state started to pursue the project seriously in the next year; the time line for power on line (POL) would likely be about ten years due to the time necessary for permitting, licensing, engineering and finally construction. So in ten years how much more of the remaining 1,500,000 Mwh would be required?? I am not sure but my feeling is that some portion of that amount would likely be utilized such that the amount available for growth once the project was completed or at least initial phases completed would be totally absorbed by the consumers thus leaving nothing substantive enough for any enterprise such as an aluminum smelter. Also I don't believe both Watana and Devil Canyon could be totally constructed in 5 years after the licensing was completed. One of the two would be complete and the other would likely still be under construction for another 3-5 years. This is the kind of staging information that would be developed in a review of the previous studies and the development of a new load forecast.
5. **One of the other detriments to the development of the project was the way the State changed the make up of the Directors of the Alaska Power Authority**. Originally the Alaska Power Authority was set up such that there was a five member board and all the members were public/ private people from the community somewhat similar to the New York Power Authority. They were to provide the long term view and guidance to the Executive Director and staff to develop power projects in the State. I am not sure when but at some point in time when there was a substantive influx of funding; the legislation that provided the funding also changed the mix of Board of Directors and it became extremely political. The change to the Board was to have four cabinet level commissioners and three private members, none of which were utility people. All Directors were to serve at the pleasure of the governor consequently every four to eight years the whole Board was replaced along with the Executive Director. This resulted in absolutely no continuity or long term planning. **The lack of long term direction is what has killed any type of Energy Plan with some type of Action Plan to be implemented over a 5, 10 and 20 year timeframe.** Any Energy Plan that is generated presently will likely have the same challenges... there has to be a way to implement long term planning without the changing ground of a new governor or new legislators. It is my understanding that there is serious consideration of extracting the successor of the Alaska Power Authority i.e. the Alaska Energy Authority from AIDEA and set it up with

similar authorities and capabilities as the old APA. Additionally, the governor is looking for an Energy Coordinator that would head up that agency. My suggestion to you and the Governor would be to set the new Board of Directors up with something like a **9 member board. It might include something like four of the Railbelt utilities represented, two SE Alaska Utility Representatives, two representatives from Rural Utilities, and a member from either the Legislature or the Administration.** Each of the Directors would have a staggered 3 year term and they would be selected by an independent Utility group (Possibly the utilities themselves or may be the membership of the Alaska Power Association). This would insure that longer term planning was occurring and that projects and plans would not be derailed every four to eight years. The Board of Directors would select the Executive Director or the Energy Coordinator. Please note that during my almost 20 years with APA/ AEA **we had four governors but we also had 20 Executive Directors (five in one year)** that guided the agency. As you may assume, this created very poor employee moral and it created high employee turnover. Utility and Energy Planning needs stability and long term planning in order to be effective.

6. **What if, you decided not to do Susitna??? What is your alternative???**
   a. Lets look at the ones first that are highly unlikely.. **Nuclear.** First off the Legislature would need to repeal a statue that prohibits the construction of nuclear plants in the state. Next one would have to initiate discussions with Dept of Energy and the nuclear department within it to discuss how one would proceed. The permitting and public comment process would be incredible. To my knowledge no new nuclear plant has been licensed in the USA for quite sometime so you would be breaking new ground. Cost of the process and just the bad PR I think would kill the possibilities of doing anything with Nuclear. Side note, a utility that my brother works for back east; took the option of putting the plant site that they had constructed in the mid 60s back to its original condition (i.e. removed the entire plant and planted grass) because they looked at the prospect of the cost associated with re-licensing an existing plant and decided that it was not worth the money or the bother.
   b. **Coal;** The state of Alaska has a huge resource of coal... why not build a coal plant... Whether or not you believe in global warming or not; there is a perception that Coal Plants contribute to that problem and the melting of our ice packs, permafrost etc. So public perception is a challenge right off the bat. The other challenge is that despite any lobbying on our part; it is apparent that Congress is going to institute a **Carbon Tax** sometime in the near future..... it is **not IF** but rather it is just a matter of **WHEN and HOW MUCH** will it be. So in addition to the cost of the plant, the fuel, the operations one would also be looking at the uncertainty of a Carbon Tax that would occur sometime in the near future. Finally, although we do things different in Alaska, one can look to our counterparts in the Lower 48 States and you will find that any number of Coal Plants that have been proposed are being stalled by environmentalist and some utilities have just pulled the plans back even after they have gone thru some very expensive permitting and engineering. Bottom line, I don't think that a coal plant is a reasonable alternative to the Susitna Project.
   c. **Natural gas Generation**; The price for natural gas to Chugach Electric Association was approximately $5/Mcf in 2006 (See CEA 2006 Annual Report page 2). Each turbine has a different heat rate efficiency and the number is probably a bit better than the 10,000 Btu/kWh that I am using here.. At that efficiency rate and the cost of natural **gas at $5/Mcf it relates to a fuel costs of approximately $0.05/kwh** (this does not include any capital costs for the installation of the plant – it is purely the fuel component). If the efficiency improves to 9,000 Btu/kWh or 8,000 Btu/kWh it drops the fuel cost to

something like $0.045 and $0.04 / kWh respectively. I do not know what the projected market price is for natural gas that would come down the new gas pipeline in 10 to 15 years???? Might it be double the $5/Mcf.... i.e. $10/Mcf.. if so based upon the 10,000 Btu / kWh we would be looking at a fuel component of close to $0.10 per kWh. One should keep this number in mind when looking at other options since it is our present situation and one could call it our base case. I would also like to suggest that one take a look at **CEA's 2006 Annual Report on page 8** it illustrates that the natural gas turbine units that they have installed were done in: **1968(2), 1972, 1975(2), 1978, and 1982 at Beluga. This means that their units are at a minimum 26 yrs old and some are approaching 40 yrs.** This is probably why for at least the short term they are working with ML&P to see about constructing a shared plant. There will need to be some short term investment to bridge the time between the present and when a new project can come on line that could provide reasonably priced energy for the long term.

d. **Other Hydroelectric Projects.** First off, I am a supporter of hydro in almost any form or shape because of its long term benefits. Most hydroelectric plants and amortized via bonds over a 20 to 30 year term yet most of them continue to produce power well beyond 100 years. Once the civil works have been put in place the replacement items are generators and turbines that turn them. These costs are minimal when compared to the overall project... They are still large numbers but they are small in comparison to the initial investment. Some of the alternatives to Susitna that have been considered in the past have been the Rampart Dam, Browne Project and some smaller hydro developments such as Snow River and the Chakachamna Project. Although these may merit some consideration, I believe anyone that looked at the Rampart or the Browne projects concluded that the areas that are covered with water would make them too environmentally detrimental to really justify their construction. The Snow River and the Chakachamna Projects are smaller projects and might provide some supplemental energy to the Railbelt but each has different characteristics that one would need to look at and decide if it was worth the merit of pursuing in more detail. The Chakachamna project has had recent activity by a private firm that has filed a Preliminary Permit on the project and is actively pursuing the project presently. They will have to "perfect" the application i.e. they have to provide information over the next three years to maintain their permit and finally file a license application if they decide that it makes sense on their part to move toward construction. Please note the peak capacity is approximately 330 Mw and the base load capacity would be approximately 165 Mw (50%) similar to the discussion above on Susitna. The energy that could be produced on an annual basis would be approximately 1,600,000 Mwh. Given the approximate energy requirement for electricity in the Railbelt of 5,000,000 Mwh in 2006, it would only provide for a small portion of it and the balance would continue to need to be provided by Gas Generation (with a questionable supply and costs component). If one is trying to stabilize electrical rates in the Railbelt and one had to balance the Chakachamna Project vs the Susitna project; the Susitna Project has a much better chance for long term stabilization of electrical rates for the area. If the Legislature decided to support Chakachamna instead of Susitna I would be disappointed but as I stated above I am a supporter of Hydro and some hydro is better than none... that is probably why Bradley Lake was constructed.. i.e. it was a good project.

e. **I fully support the pursuit of the Natural Gas Line** but at the same time I have to raise the issue that it is not a renewable source. Back in the mid 70's the State pushed and the Oil companies constructed the Oil Pipeline and production began in I believe it was 1978 or about that timeframe. It has been thirty years since then and oil production has dwindled down to the point that in the next five to ten years there will likely not be enough available oil to justify the expense of operating the pipeline. So our **"Oil Cash Cow"** is going to disappear and we are hoping to replace it with a **"Natural Gas Cash Cow"**.... Which I believe is definitely good but at the end of 30 to 40 years we will be in the same position we are today i.e. gas reserves dwindling and the question at that point would be what do we do now???? **Let's not repeat history.** My suggestion is that instead of waiting the next 30 years again; the State builds the Susitna Project and pay off the bonds over a 20 to 30 year period probably with Power Sales Contracts with the Railbelt Utilities and some of the Natural Gas Revenues used as equity.. **Once the bonds are paid off then the remaining revenue stream (i.e. the revenue that would come from the sale of electricity less the operational costs) could be put back into the General Fund or the Renewable Energy fund so that it could help operate Government or build new infrastructure for new generation.** Originally, the idea for Susitna was to take the Oil Revenue (non-renewable resource) and use a portion of it to construct Susitna, a renewable resource and utilize the revenue off of Susitna for other State Projects/ Operations. Although the bonds may take 30 or so years to pay off; the project will have a real life of probably 100 Plus years. My guess is that it would likely still be around 200 years from now. The project has the potential to stabilize the rates in the Railbelt for many years which means that it would also create an economic environment that business and local citizens would be able to exist without the threat that the cost of electricity was going to push them out of the state. Stable rates create certainty which eliminates one less challenge in keeping businesses going.

7. **Previous Reports and documents?** Please note that in the mid 1980s when it was decided to stop work on the project it was decided that the State would not just drop the ball and throw all of what was done out the window but rather to organize and place the hard work that was completed someplace where it could be retrieved at a later date if one wanted to continue with the project. Additionally, it was felt that there was immense amounts of data that could be utilized by College Professors, Graduate Students and Undergraduate Students. Consequently, about 140 file boxes were labeled, indexed and shipped to the University of Alaska, Fairbanks Library System to be stored there and utilized by the academic population and if the need came up someday it would be available for resurrecting the project. You will also note that the Alaska Power Authority provided copies of most if not all the Published Reports to the 18 or 20 designated State Libraries through out the State of Alaska. The State Library in Juneau should have those reports and also the other libraries around the State. The Compendium of file boxes that were shipped to Fairbanks not only contain the Reports that were completed but many of the data files, computations, drill logs, and other back up information on the project.
8. **Are the documents and reports pertinent today or are they so out of date that they are not of any value?** The answer is that some information is likely way out of date and not of value but there is a good portion of it that is very valuable. As an example the cost estimates probably do not reflect today's prices but the estimates of the amount of concrete, steel, dirt to be moved etc all of those units would likely provide a good starting point for any revised cost estimate and for that matter even if you were going to change the project configuration somewhat, it would give you a great baseline to start from. All of the Geologic drilling and drill logs are excellent information. Many of the previous consultant companies and personnel are still alive and could be contacted for background information and confirmation of the different aspects of the project. **Please**

note AIDEA/AEA has placed "Susitna Hydroelecric Project, Economic & Financial Update, February 27, 1984" out on the AEA web site. Although dated, this document would be a good place to start as a template to update costs and revised analysis of the overall project. Obviously, some of the models referenced may no long be applicable or even available today out new improved models etc could be utilized to complete a similar analysis.

9. **What will it take to move the project forward and what kind of timeframe?** If you take a look at the past history of what the funding scenarios were and the time that it took to get from the initial studies to where by one could start construction; it will provide some characterization of what you should expect. One should not go into the project blindly and you should realize that it is going to take time and money. My recollection of the budgeting process was that it took approximately $20 M to $30 M on an annual basis to conduct the necessary engineering, environmental, permitting, legal etc. processes to move the project along. Agreed much of this information has been developed and also is on file but at the same time the licensing agency i.e. FERC and all the resource agencies from the US Fish & Wildlife Service, National Marine Fisheries, ADF&G, Dept of Environmental Conservation, EPA, Corp of Engineer, the Native land owners Federal land owners, etc will want to see updated information before they sign off or any license application / EIS. That means a fair amount of field data will need to be collected and compared with the previous data and then the consultation process has to occur. There are very lengthy review times and responses that have to be worked thru. My general feeling is that it will take a minimum of three years to get thru the permitting/ licensing process and it may take a bit more i.e. may be up to five years. At that point one would have a license to begin construction and you would move forward with construction. Soo you probably are looking at an investment of $100 M to $150 M over a five year period to get to the point where by you could construct a project. As I understand it presently, there is approximately $80 M in the Railbelt Energy Fund. I would suggest that the initial investigations and permitting be funded out of this area.
10. **Financing???** I have not discussed the financing of the project but that is a whole other discussion on the different options and what would be needed. There is the potential for Federal Grant funding, Federal loan funds, Tax exempt bonds, etc but there is going to have to be a certain amount of State Equity in the project to make it go forward. The one item that I believe that will be required is some type of equity contribution by the State of Alaska. Previous, analysis (See the study listed on the AEA web site – Susitna Hydroelectric Project – Economic & Financial Update, February 27, 1984) indicated that about $2 Billion was to be required in State Contribution in order to bring the rates in the early years close to the existing rates. That was back when the cost of gas was substantially lower and there was no real concern about the supply of gas. **My initial guess is that there will likely need to be a minimum of about $2 Billion of State contribution and potentially bond the balance of the costs.** It may be more but I believe the Legislature and the Governor should be walking into the room with the knowledge and concept that there will have to be a substantive investment by the State in the neighborhood of $2 Billion in order to make the project go forward. I would suggest that the Legislature begin to put away that equity requirement today i.e. it could be that for the next ten years approximately $200 to $250 M be placed in an interest bearing account to accumulate the moneys that will be required at the end of the five year engineering, permitting period and one would be ready at that time to be able to show any bond holder that you have your equity portion available for the investment into the construction of the project. The financing could be staged also to coincide with the

different portion of the project i.e. the Watana development first and the more expensive portion; then the Devil Canyon portion.

I hope this information is helpful.
Additional Questions???

Respectfully,
Eric Marchegiani, PE
19013 Richner Rd
Chugiak, Alaska 99567
Email: ericmary@mtaonline.net
Tel # 1-907-688-3343

Susitna						
Revise to about double the costs						
w/ $2.25 B Equity Investment						
		Energy	Annualized			
Susitna		(MWH)	Costs	Costs		
Devil Canyon	600		(20 yrs)	($/kwh)	Term (yrs)	35
		6,500,000	$761,871,439	$0.1203	Interest	6%
Watana	1020				Costs(PV)	-$11,045,799,825
					PMT	$761,871,439
					O &M	$20,000,000
Guess on Phased Construction						
Susitna					Term (yrs)	35
Devil Canyon	600	3,210,000	$386,686,766	$0.1223	Interest	6%
					Costs(PV)	-$5,606,280,000
					PMT	$386,686,766
					O &M	$6,033,520
					Term (yrs)	35
Watana	1020	3,290,000	$375,184,673	$0.1183	Interest	6%
					Costs(PV)	-$5,439,519,825
					PMT	$375,184,673
					O &M	$13,966,480
Total Enegy of Two Projects (MWH)		6,500,000				
Watana Proportion of Energy	49.385%	3,210,000				
Devil Canyon Proportion of Energy	50.615%	3,290,000				

		Wanta	Devil Canyon			Cash	Interest on	Interest Dur	RUS	RUS
Exhibit 7.4		Construction	Construction	Equity	Cum	Balance	Equity	Construction	Loan-Draw	Loan-Draw
Old Schedule		Costs	Costs	Contribution	Equity		5%	6%	6%	6%
(Year)	(Year)	$ Millons	$ Millons	$ Millons	$ Millons	$ Millons	$ Millons	$ Millons	$ Millons	$ Millons
1985	2013			$ 300	$ 300	$ 300	$ 15			
1986	2014			$ 300	$ 600	$ 615	$ 31			
1987	2015			$ 300	$ 900	$ 946	$ 47			
1988	2016			$ 300	$ 1,200	$ 1,293	$ 65			
1989	2017	$ 566		$ 300	$ 1,500	$ 1,092	$ 55			
1990	2018	$ 529		$ 250	$ 1,750	$ 867	$ 43			
1991	2019	$ 634		$ 250	$ 2,000	$ 527	$ 26			
1992	2020	$ 743		$ 250	$ 2,250	$ 60	$ 3			
1993	2021	$ 1,373				$ (1,310)		($79)	-$1,389	
1994	2022	$ 1,485				$ (2,795)		($168)	-$1,653	
1995	2023	$ 1,343				$ (4,138)		($248)	-$1,591	
1996	2024	$ 527				$ (4,665)		($280)	-$807	
1997	2025		$ 500			$ (500)		($30)		-$530
1998	2026		$ 800			$ (1,300)		($78)		-$878
1999	2027		$ 1,100			$ (2,400)		($144)		-$1,244
2000	2028		$ 900			$ (3,300)		($198)		-$1,098
2001	2029		$ 700			$ (4,000)		($240)		-$940
2002	2030		$ 638			$ (4,638)		($278)		-$916
							Tot Interst	$ (1,743)		
	Total	$ 7,200	$ 4,638	$ 2,250			Watana RUS Loan		-$5,440	
								Devil Canyon RUS Loan		-$5,606
	Watana & Devil Canyon		$ 11,838							

Replaced 3/25/08

FISCAL NOTE

STATE OF ALASKA
2008 LEGISLATIVE SESSION

Fiscal Note Number: 1
Bill Version: CSHB 336(RES)
(H) Publish Date: 2/11/08

Identifier (file name): HB336-CED-AEA-01-25-08
Title: Susitna Hydroelectric Project
Sponsor: Johnson et al
Requester: Resources

Dept. Affected: DCCED
RDU: Alaska Energy Authority (453)
Component: Statewide Project Development
Component Number: 2888

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	Appropriation Required	Information					
OPERATING EXPENDITURES	**FY 2009**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**
Personal Services							
Travel							
Contractual							
Supplies							
Equipment							
Land & Structures							
Grants & Claims							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	1,000.0						
CHANGE IN REVENUES ( )							

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts							
1003 GF Match							
1004 GF							
1005 GF/Program Receipts							
1037 GF/Mental Health							
Other Interagency Receipts							
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2008) cost: ________

POSITIONS

Full-time							
Part-time							
Temporary							

ANALYSIS: *(Attach a separate page if necessary)*

This legislation requires the Alaska Energy Authority (AEA) to conduct a study and prepare a proposal for a hydroelectric power project on the Susitna River appropriately sized for the Railbelt Area.

The project would be significant in scope and would likely extend beyond one year; therefore, we suggest a capital appropriation. It is likely additional funds would be required, but these amounts are indeterminate at this time.
We assume that AEA would develop a best fit scenario, and develop a preliminary design to provide enough detail that a valid project concept cost estimate and schedule could be developed and reported to the Legislature no later than June 30, 2010.

Prepared by: Sara Fisher-Goad, Deputy Director - Operations
Division: Alaska Energy Authority
Phone: 907-771-3012
Date/Time: 1/25/08 9:00 AM

Approved by: Emil R. Notti, Commissioner
Commerce, Community, and Economic Development
Date: 1/25/2008

(Revised 11/19/2007 OMB)

FAX COVER SHEET

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From: PAUL D. KENDALL Phone:

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Hydrogen Fuel Fuel Cells

Home of the Future

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PIPED CONCEPT

Paul Kendall — Economic Independance —

HYDROGEN USE IN ALASKA

Project 40902 Final Report

Christopher F. Blazek
Timothy D. Donakowski
Martin Novil
Edward J. Daniels

A Case Study
Outline
1981

Prepared by
Institute of Gas Technology
IIT Center, 3424 S. State Street
Chicago, Illinois 60616

Date Published — November 1981

Prepared for the
U.S. DEPARTMENT OF ENERGY
And
STATE OF ALASKA
Under Contract No. DE-AC02-80CS91201

11/81

Table ES-1. DEMONSTRATION COMMUNITY COSTS

Stage of Project	Item	Size or Number	Cost,* $10^3
Preliminary Investigations	None	--	--
Field Studies	None	--	--
Offsite R&D	Appliance Testing	6 month	100
Demonstration Project			
Phase I	H_2 Storage	4 x 10^6 SCF	1,600
	Fueling Station	1	50
	Automobile Conversions	25	50
	Three-Wheeler Conversions	45	90
	Boat Conversions (gasoline)	25	50
	Boat Conversions (diesel)	15	300
Phase II	Alternate Wind Power System ($1100/kW + 60 Mills/kW hr)	220 kW	240
	Electrolyzers (current technology)	1600 SCF/hr	100
Phase III	H_2 Storage	35 x 10^6 SCF	8,000
	Distribution System	400 people	720
	Furnace Conversions	100	40
	Water Heater Conversions	100	15
	Range	100	15
Phase IV	Alternative Wind Power System	1900 kW	2,100
	Electrolyzers	14,000 SCF/hr	870
Phase V	Alternative Wind Power System	500 kW	550
	Electrolyzers	1500 SCF/hr	100
	H_2 Storage	260,000 SCF	280
	Fuel Cell System ($600/kW)	150 kW	90
Evaluation	None	—	—
		Subtotal	14,360
	Freight + Contingency (30%)		4,300
Support Staff			1,030
		Total	19,690

Paul D. Kendall

100 homes

* Assumes 1 month storage.

x

National Geo 11-93 Special Edition 'Water' COMPUTER IMAGE BY CHUCK CARTER Paul O. Kendall

The world's water supply

If all earth's water fit in a gallon jug, available fresh water would equal just over a tablespoon— less than half of one percent of the total. About 97 percent of the planet's water is seawater; another 2 percent is locked in icecaps and glaciers. Vast reserves of fresh water underlie earth's surface, but much of it is too deep to economically tap.

LITTLE CYCLONES END SEVEN-GAME LOSING SKID

See SPORTS, C1

THE TRIBUNE

Paul O. Kendall

WHERE ARE OUR [redacted] LEADERS ON THIS $?

VOL. 136 – NO. 302 | AMES, STORY COUNTY, IOWA | WEDNESDAY, JUNE 23, 2004 50¢

Paul Kendall

Cutting-edge energy

Proposed wind and hydrogen plant for Ames would be world's first

BY BETH ANDERSON
Staff Writer

The Ames Laboratory is proposing to build the world's first wind and hydrogen energy plant in Ames under a three-way partnership with the city and Iowa State University.

Tom Barton, the director of the Ames Lab, went before the Ames City Council Tuesday to seek support for a project that could provide inexpensive electricity for the city, be a source of hydrogen for research and place Ames in the international spotlight for renewable energy.

INSIDE: ANGRY CROWD OF HOMEOWNERS CONFRONTS COUNCIL OVER SIDEWALKS.

Page A6

"It could be a win-win-win deal," Barton said.

The council unanimously approved a motion to move the project forward, directing staff to work with the Ames Lab.

The proposed project would erect two wind turbines in west Ames that would provide electricity by converting water to hydrogen.

But the Ames plant will go beyond the standard wind turbines because of its ability to store energy using underground hydrogen fuel cells as "batteries," Barton said. The hydrogen could then be reconverted into electricity on demand.

With the go-ahead from the city, the plant could be up and running within 18 months or less, he said.

ENERGY please see page B3

Energy: Federal funding likely

Continued from page A1

6/23/04 Paul Kendall

Major funding for the project would likely come from the U.S. Department of Energy, which is working on a White House mandated Hydrogen Fuel Initiative to develop the technology needed to find a practical and inexpensive way to convert water into hydrogen fuel.

Barton gave no cost estimate for the proposed Ames project, but said that each of the three entities would play a part in its creation.

ISU will be asked to provide land for the project, possibly one of the university farm sites north of Lincoln Way on County Line Road.

The city would acquire all needed permits and allow connection to the intercity power grid, according to the proposal.

Because each wind turbine could produce as much as $100,000 worth of electricity a year, it is conceivable that Ames could someday have the option to sell part of the energy to other municipalities, Barton said.

The energy plant would be developed and operated by the Ames Lab, which would use the hydrogen produced to continue its research, particularly in a search for a hydrogen hybrid metal.

The Ames Lab is a Department of Energy laboratory operated by ISU on the Ames campus.

Its roots go back to the 1940s, when Ames produced more than 2 million pounds of uranium for the Manhattan Project.

Staff writer Beth Anderson can be reached at 232-2161, Ext. 353, or at banderson@amestrib.com

(1)

BP Gas and power - Renewables & Hydrogen
Renewables & Hydrogen products and services - BP ... BP Gas and power Products and Services Renewables & Hydrogen ... ensure BP is ready to offer hydrogen to ...
bp.com/sectiongenericarticle.do?categoryId=3050016&contentId=3050076 - 30k - Cached

BP Global - Press - Introducing hydrogen power
BP's plan to generate electricity from hydrogen and capture carbon dioxide could ... electricity using hydrogen manufactured from natural gas to create " ...
www.bp.com/genericarticle.do?categoryId=97&contentId=7006978 - 44k - Cached

Ford Motor Company - Press Release - FORD AND BP OPEN FIRST HYDROGEN ...
With BP providing hydrogen fuel, this event will provide a chance to see ... fuels" said Maria Curry-Nkansah, BP's hydrogen business development manager. ...
media.ford.com/newsroom/release_display.cfm?release=24585 - 19k - Cached

BP's only UK hydrogen station demolished - AutoblogGreen
BP's only UK hydrogen station demolished. Posted Jun 11th 2007 8:16PM ... For the past three years, BP has had a hydrogen filling station at Hornchurch in ...
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People's Daily Online -- China's first hydrogen refueling station goes ...
A website by the People's Daily newspaper; China, business, world, science, ... said Bill Fitzharris, general manager of BP hydrogen transport technology. ...
english.people.com.cn/200611/09/eng20061109_319883.html - 28k - Cached

Singapore Environment Institute
... world's largest energy company, BP sees hydrogen as offering the potential to ... this position, he leads the BP hydrogen programme, directs the existing project ...
www.nea.gov.sg/cms/sei/PSS4.html - 12k - Cached

California Hydrogen
... announcement, BP had already announced plans for two such hydrogen power ... near BP's current oil-refining operations that heavily use hydrogen to produce ...
www.cleanfleetreport.com/vault/carson.htm - 11k - Cached

Ford and BP Open Hydrogen Station in Taylor, Another Milestone in ...
With BP providing hydrogen fuel, this event will provide a chance to see ... fuels," said Maria Curry-Nkansah, BP's hydrogen business development manager. ...
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Green Car Congress: BP and Rio Tinto Form JV for Hydrogen-Fueled Power ...
Online news. ... BP and Rio Tinto have formed a new jointly-owned company, Hydrogen ... BP's previously announced hydrogen-fueled power projects in ...
www.greencarcongress.com/2007/05/rio_tinto_and_b.html - 19k - Cached

Media.Ford.com: FORD & BP TO BUILD HYDROGEN FLEETS & FUELING STATIONS ...
OFFICIAL NEWS, PHOTOS, VIDEOS, MEDIA KITS, EXECUTIVE BIO&146;S, PRESS ... to place up to 30 hydrogen-powered vehicles, and BP plans to build a network of ...
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3-5-08
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Two oil giants plunge into the wind business - The Boston Globe
... some of the biggest players in wind power in the United States, accelerating a ... five generators of wind power, while BP's Alternative Energy group – launched ...
boston.com/news/.../03/02/two_oil_giants_plunge_into_the_wind_business - 40k

Clipper Windpower Completes Sales Contract With BP For Delivery of 300 ...
... or 300 MW, of Clipper's 2.5 MW Liberty wind turbines to BP for delivery in 2009. ... In the United States, BP's wind portfolio includes the opportunity to develop ...
prweb.com/releases/2007/9/prweb556233.htm - 48k - Cached

BP Alternative Energy Acquires Wind Energy Co.
... 2005 to bring together BP's low-carbon electricity businesses. ... a small wind farm on a small acreage that gets sweeping winds year around in SW Indiana? ...
www.renewableenergyaccess.com/rea/news/story?id=47040&src=rss - 36k - Cached

ALTERNATIVE ENERGY BLOG - Solar-Energy-Wind-Power.com: $4b Investment ...
... strong opinions on alternative energy resources including wind power, solar energy, wave energy, geothermal & other ... BP is making its first major investment ...
alt-e.blogspot.com/2006/07/4b-investment-in-wind-power-by-bp.html - 39k - Cached

Clipper Windpower Press Release
... COMPLETES SALES CONTRACT WITH BP FOR DELIVERY OF 300 MW OF WIND TURBINES IN 2009 ... In the United States, BP's wind portfolio includes the opportunity to develop ...
www.clipperwind.com/pr_092607.html - 10k - Cached

BP Breaks Ground On First Wind Project In Texas
BP broke ground today on its first wind project in Texas. ... BP believes that sustainable energy alternatives and the development of the wind ...
www.renewableenergyaccess.com/rea/news/story?id=49928&src=rss - 18k - Cached

Rocky Mountain News - Denver and Colorado's reliable source for ...
BP's foray into the local wind industry came about recently when it bought ... BP's wind energy investment here is on top of its continued focus to increase ...
rockymountainnews.com/drmn/energy/article/ ... - 38k - Cached

North American Windpower: Content / Projects & Contracts / BP Plans To ...
BP Plans To Begin Building Five Wind Farms in 2007 ... a wind project developer under BP PLC, has announced that it expects to begin ...
www.nawindpower.com/naw/e107_plugins/content/content.php?content.377 - 17k - Cached

1 2 3 4 5 6 7 8 9 10 11 Next >

(3)

11 - 20 of about 3,980,000 for bp wind

Windtech International - BP breaks ground on wind project in Texas
... International is the worldwide information magazine for the wind energy industry. ... first application at scale of Clipper's new C-96 wind turbine technology for BP. ...
www.windtech-international.com/content/view/1427/1 - 20k - Cached

Windtech International - BP Alternative Energy purchases wind power ...
... International is the worldwide information magazine for the wind energy industry. ... acquisition of Orion. BP's North American wind portfolio includes an opportunity ...
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ENN: BP Breaks Ground On First Wind Project In Texas
... new Texas wind power facility will see 24 2.5 megawatt wind turbine generators. ... BP believes that sustainable energy alternatives and the development of the wind ...
www.enn.com/energy/article/23030 - 15k - Cached

BP p.l.c. - Information & Fact Sheet - Hoover's
BP is also BO (Big Oil). It is the world's second largest integrated oil concern, behind Exxon Mobil. The company, which was formed in 1998 from the merger of British...
www.hoovers.com/bp/--ID__58872--/free-co-factsheet.xhtml

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BP Breaks Ground on First Wind Project in Texas " Earth 911
Houston, TX — BP broke ground today on its first wind project in Texas. ... BP believes that sustainable energy alternatives and the development of the wind ...
earth911.org/blog/.../bp-breaks-ground-on-first-wind-project-in-texas - 44k - Cached

energyme.com :: BP wind projects for 2007
Your single source for ... BP's US wind portfolio includes the opportunity to develop ... the year, BP acquired two US wind development companies ...
www.energyme.com/energy/2007/200700028.htm - 10k - Cached

Yankton Press & Dakotan: Story
BP brings capital and expertise to Clipper's effort at developing wind ... 200MW in 2008 which it will use on other projects in BP's global wind business. ...
www.yankton.net/stories/080906/community_20060809038.shtml - 27k - Cached

BP Alternative Energy Buys US Wind Company
... will allow BP to accelerate its plans to develop a leading wind power business in North America. ... BP Alternative Energy announced it had reached ...
www.azom.com/details.asp?newsID=6358 - 35k - Cached

Wind Energy
Harnessing the power of wind...(Skandia) It is the ultimate renewable resource. ... Sharp, Kyocera, and BP are also large manufacturers of solar modules, but this ...
www.wikinvest.com/concept/Wind_Energy - 64k - Cached

< Prev 1 2 3 4 5 6 7 8 9 10 11 Next >

BP and Rio Tinto unite to develop clean energy projects

■ VENTURE: Company initially will look into hydrogen-fueled power.

The Associated Press

LONDON — Oil producer BP and miner Rio Tinto will be working together to develop clean power projects around the world, the companies said Thursday.

The joint venture will initially focus on hydrogen-fueled power generation, using fossil fuels and carbon capture and storage technology to produce new large-scale supplies of clean electricity.

"Projects such as these have the potential to help deliver the carbon emission reductions which companies and countries around the world are now seeking," said BP Chief Executive Tony Hayward.

BP said that previously announced hydrogen-fueled power projects in Peterhead, Scotland, and Carson, Calif., will become part of Hydrogen Energy. Rio Tinto will make a cash payment to BP of about $32 million, subject to post-completion adjustments.

The new company will be based in Weybridge in southeast England and will initially have a staff of 75 transferred from the parent companies.

Lewis Gillies, formerly head of BP's hydrogen power business, will be chief executive of Hydrogen Energy, and Peter Cunningham, formerly head of business evaluation for Rio Tinto, will become chief financial officer.

Paul D. Kendall

from page 20

smission Facilities for Re-
enerators," the new catego-
)e defined as "high-voltage
:on facilities necessary to
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this category, transmission
over the initial costs of
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is aiming for FERC to ap-
concept of the proposal
le feedback if there are any
fill. According to Perez,
time limit for FERC to re-
)roposal, but he hopes to
ponse by April. If they do
approval, CAISO would
to acquire the stakehold-
which would most likely
o three months, and then
le the proposal with FERC.
m President Bush's recent
ie Union address, which
generating more renew-
, Perez believes FERC will
e proposal.

"If you've been following all the action in Washington, D.C., the action has been renewables, renewables and renewables," he says. "Here we're coming with a proposition that will facilitate renewable development. If I were a betting man, I would bet they would pass it."

– *Shelley Paventy*

Paul D. Kendall

Wind Power Increases Worldwide

NAW 02-07

Reports from the American Wind Energy Association (AWEA), the European Wind Energy Association (EWEA) and the Global Wind Energy Council (GWEC) show solid growth in wind power markets around the world.

In terms of new installed capacity in 2006, the U.S. continued to lead with 2,454 MW, followed by Germany (2,233 MW), India (1,840 MW), Spain (1,587 MW), China (1,347 MW) and France (810 MW), according to GWEC's annual figures for 2006.

AWEA reported in its recent market forecast that wind power generating capacity in the U.S. increased 27% to 11,603 MW in 2006 and is expected to increase an additional 26% in 2007.

"iPods, flat screen televisions and other highly sought technologies are creating a demand for electricity that is beginning to eclipse our current supply," says Randall Swisher, executive director of AWEA. "Wind is a proven, cost-effective source of energy that also alleviates global warming and enhances our nation's energy security."

The forecast indicates the U.S. wind energy industry invested approximately $4 billion in new installations, making wind energy the second largest source of new power generation in the country, behind natural gas.

AWEA's industry outlook also found that:

- Texas accounted for nearly a third of the new wind power installed in 2006,
- new utility-scale turbines were installed in a total of 20 states across the country and
- the top five states in new installations were Texas (774 MW), Washington (428 MW), California (212 MW), New York (185 MW) and Minnesota (150 MW).

GWEC's annual figures for 2006 reveal that 15,197 MW of wind energy was installed in 2006 around the world, bringing the total installed wind energy capacity for more than 70 countries to 74,223 MW – up from 59,091 MW in 2005. The countries with the highest total installed capacity are Germany (20,621 MW), Spain (11,615 MW), the U.S. (11,603 MW), India (6,270 MW) and Denmark (3,136). Thirteen countries around the world can now be counted among those with over 1,000 MW of wind capacity, with France and Canada reaching this threshold in 2006.

According to EWEA, 7,588 MW of wind power capacity, worth approximately 9 billion euros, was installed last year in the European Union (EU) – an increase of 23% compared to 2005. The cumulative wind power capacity operating in the EU increased by 19% and now exceeds 48,000 MW.

AAER To Open Plant

Bromont, Quebec-based wind turbine manufacturer AAER Inc. has signed a ten-year lease agreement, with an option for an additional five years, with Olymbec Inc., the owner of buildings that housed the former Hyundai plant in Bromont.

Under the terms of the agreement, AAER has leased 111,141 squar feet to be used for the assem-

MAR-05-2008 WED 03:42 PM ANCHORAGE LIO FAX NO. 907 269 0229 P. 11

ACTS

...ission, the RPS requires each investor-owned utility to increase its ...ocurement of eligible renewable ...nerating resources by 1% of load ...r year to achieve a 20% goal. Buc... Vista will provide over 38 MW of ...nd power to the state's electricity ...stomers.

"We are very glad to partner with ...G&E in the first and important re...wering in the Altamont area," says ...ike Garland, head of Babcock & ...own's North America Infrastructure Group, the developer of the ...oject."

...ntario Project ...tarted

Acciona Wind Energy Canada ...c., a renewable energy project developer and affiliate of Acciona S.A., ...d Suncor Energy Products Inc., a ...holly owned subsidiary of Suncor ...ergy Inc., have started construction on a 76 MW wind farm located ...ear Ripley, Ontario.

Foundations for the 38 2 MW ...nercon wind turbines are now be...g poured. Pending weather conditions, construction will take a brief break during the winter months and is expected to be complete this summer, with the project commissioning scheduled for late 2007.

The wind farm is located in Huron-Kinloss township, approximately 220 kilometers west of Toronto. The project is expected to have the capacity to power 24,000 homes and offset 66,000 tons of carbon dioxide per year.

In addition, Suncor and Acciona will submit an application for funding from the Canadian government's recently announced ecoEnergy Renewable Power Initiative, which supports wind power development in Canada.

March-07

BP Plans Five Wind Farms

NAW 02-07

BP Alternative Energy North America Inc., a wind project developer under BP PLC, has announced that it expects to begin construction on five wind power projects in the U.S. in 2007.

According to BP Alternative Energy, the projects are expected to deliver a combined capacity of approximately 550 MW. Construction is currently underway on the 300 MW Cedar Creek project, a development venture between BP Alternative Energy and Babcock & Brown, in Weld County, Colo. The 274 turbines that the project calls for will be erected on a 32,000-acre site. According to Governor Bill Ritter, D-Colo., who supports the wind farm, it will create up to 250 jobs and has the capacity to power 120,000 homes.

NOTE: 250 homes p/MW x 300 MW 75,000 Homes @ 27% wind flow

The remaining projects include a 65 MW wind farm in North Dakota, a 60 MW joint project with Clipper Windpower in central Texas, a 100 MW project in western Texas, and the Yaponcha wind power project in California. The Yaponcha project consists of repowering an existing wind energy facility in San Gorgonio Pass – the company expects the facility to have a capacity of 20 MW.

"Our 2007 build program surpasses our target and does so a year ahead of schedule," says Robert Lukefahr, president of BP Alternative Energy. "It is a testament to the caliber of people working in our business and the opportunities in the U.S. wind sector."

BP Alternative Energy adds that it plans to deploy 150 MW of Clipper Liberty wind turbines in the projects as part of the supply and joint development agreement it entered into in 2006 with Clipper Windpower.

BP just built Hydrogen Refueling station in Beijing China.

NBP, TransAlta Enter PPA

Calgary, Alberta-headquartered TransAlta Corp., a generator of electricity from a variety of sources, including renewable energy, has entered into a 25-year power purchase agreement with New Brunswick Power, a New Brunswick-based power supplier. The agreements represent the province's second power purchase agreement.

Under the terms of the agreement, TransAlta will provide 75 MW of wind power to New Brunswick Power. TransAlta will construct, own and operate a wind power facility in the Kent Hills area of New Brunswick. Natural Forces Technologies Inc., a local Atlantic Canada wind developer, is TransAlta's co-development partner in the project.

The 25-turbine wind farm is subject to regulatory and environmental approvals, and is expected to begin commercial operation by the end of 2008, the companies say. Once complete, it will provide a capacity of 220,000 MWh per year, which is enough electricity to meet the needs of approximately 13,600 homes. The ıe proposed facilities :sota Power's electric near Hewitt, Minn., says. Barnesville, artered Bear Creek LLC would build, ate the wind farm, ıture 13 2.5 MW tur- tured by Germany-

Bear Creek, the initial ted to be operational ar – once that is erect- l turbines will be in- capacity of 32.5 MW. ; expected to be com- nnesota Power adds.

rican 40 MW

ı Energy Co., a Des ased electric utility of MidAmerican En- Co., is seeking ap- Iowa Utilities Board 40 MW of wind en- s power supply.

"In addition to the environmental benefit of adding new wind energy production in Iowa, customers of MidAmerican Energy will continue to benefit from electric rate stability," says Greg Abel, president of MidAmerican Energy Holdings. "The last electric rate increase MidAmerican Energy customers experienced was in 1995, and we propose adding the new wind energy while maintaining electric rate stability until 2014, which is nearly 20 years of electric rate stability for MidAmerican Energy customers."

In addition, the company has announced plans to erect a wind turbine for renewable energy generation at the Iowa State Fairgrounds. The Iowa State Fair wind turbine will be built in part due to the voluntary customer donations to MidAmerican Energy's Renewable Advantage program. Since its inception in 2004, more than $150,000 has been donated to the program. MidAmerican Energy will fund the remaining $743,000 required to erect the wind turbine and make a $4,000 annual payment for the easement for the wind turbine site, the company says.

Construction of the turbine is scheduled to begin this spring and be completed in time for this year's fair, MidAmerican Energy adds.

June - 07

BP Orders Wind Turbines

Vestas Americas A/S of Portland, Ore., has received an order from BP Alternative Energy North America Inc. for 50 V90-3.0 MW wind turbines to accelerate the growth of BP's U.S. wind portfolio.

According to the companies, delivery of the turbines will commence in the fourth quarter of this year. Vestas will supply and commission the 50 wind turbines as well as maintain and service them for five years.

"The V90-3.0 MW turbine is an important part of our growth in the North American marketplace, and we are pleased that BP has included this turbine type in its wind portfolio," says Jens Soby, Vestas Americas' president.

150 MW

THERE IS NO SUCH THING AS WATER! - ONLY VARIOUS HYDROGEN COMPOUNDS! PAUL D KENDALL

PAUL D. KENDALL 222-7882 4-12-07 TO: ACIA REVIEW

8. TECHNOLOGY DEVELOPMENT

*"...the discovery with which we are dealing involves forces of nature too dangerous to fit into any of our usual concepts." (The Congressional Record of 1875, concerning the discovery of gasoline).**

HYDROGEN?

* Quoted by Anthony M. Moos in *Fuel Cells*, Vol. II, ed. G. J. Young, (New York: Reinhold Publishing Corpo ation, 1963).

THESE FIGURES ARE NOT VERIFIED!

NEED Validity!

Paul D. Kendall

11-16-07 ENERGY OUTLAYS

ENERGY	Annual Nat Avg	Annual AK Avg	X X SFHOM Annual SFHOM Avg	Monthly SFHOM	Annual X 1,000 homes = cu ft. nat gas
Natural Gas		175,000 cu ft.	150,000 cu. ft.	12,500 cu. ft.	150,000,000 cu. ft.
1 cu.ft.=1,031 btu		180,425,000 btu	154,650,000 btu	12,887,500 btu	154,650,000,000 btu
		175 Mcf	150 Mcf	12.5 Mcf	150. MMcf
*Electricity		8,500 Kwh	7,200 Kwh	600 Kwh	7,200,000 Kwh
1 kwh=3,412 btu		29,002,000 btu	24,566,400 btu	2,047,200 Btu	24,566,400,000 btu
		28,130 cu. ft.	23,828 cu. ft.	1,986 cu. ft.	23,828,000 cu.ft.
		28.1 Mcf	23.828 Mcf	1.986 Mcf	23.828 MMcf
Gasoline	468 gal.	1,500 Gal	1,000 Gal	250 Gal.	1,000,000 Gal
1 Gal=124,000 btu		186,000,000 btu	124,000,000 btu	31,000,000. btu	124,000,000,000 btu
=120.3 cuft		180,407. cu. ft.	120,272. cu. ft.	30,068. cu. ft.	120,272,000 cu. ft.
		180.4 Mcf	120.3 Mcf	30.1 Mcf	120.3 MMcf
Water					
Sewage					
Property Taxes					

2 3/4 Gal / day 19 Gal/wk

$ p/cu ft
120.3 cu/Gal

303,2[illegible]
[illegible] Mcf

294 MMcf
294,000,000 cf
$1,470,000 p/yr

* check on gas amount to produce – power loss in transmission

$1470.00
@ $5.00/1000 Mcf

Bill Noble

2006 – FERC – 11%
LNG · 36.7%
N.Jme 19.6%
Power 21.8%
90%

Paul D. Kendall
3/5/08

Old Booklet

HISTORY AND DEVELOPMENT OF STEAM BOILERS

TALK BY S.T. MACKENZIE

SALES MANAGER

THE BABCOCK & WILCOX COMPANY

BOILER DIVISION

TO

NORTH CAROLINA SOCIETY OF ENGINEERS

WILMINGTON, N.C., AUGUST 5, 1954

BULLETIN 3-592

History and Development of Steam Boilers

by S.T. Mackenzie

Each state in the union has its own particular claim to fame, but when I think of "North Carolina" there always comes into my mind a picture of good, sound progress symbolizing a spirit that is cognizant of tradition, but not hopelessly chained to it; a spirit dedicated to advancement but not always seeking the new merely for the sake of change.

There are many things which make North Carolina a great state. Its people, its resources, its enterprises. Important among the elements that have contributed to the rapid growth of your state is the presence of many engineers and their organization into societies such as you have here. Progress doesn't just happen. It takes enterprise. It takes thought. It takes courage. Most of all, it takes engineers. Without engineers to translate dreams into practical, working, economical reality, we would be a poorer, weaker nation.

We cannot single out any branch of engineering as being a greater contributor than any other to our mutual progress. We are all too interdependent, need each other too much to draw any fine distinctions.

No place is this better illustrated than in the subject which I am discussing today: "The History & Development of Steam Boilers". Perhaps I should have called it: "More Steam - Less Muscle".

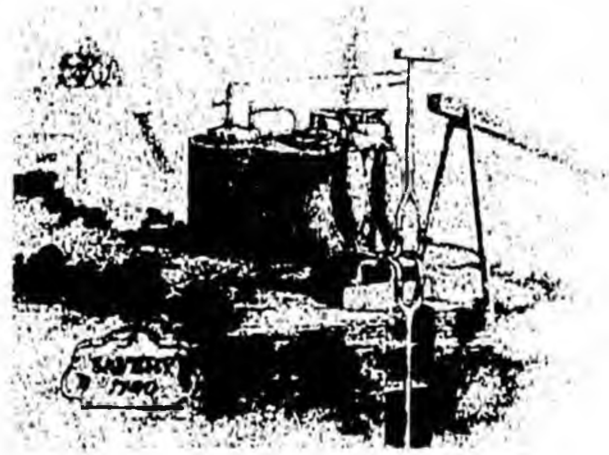
Offhand, nothing sounds quite so commonplace as steam boilers. They've been around for years. It might be more exciting to talk about supersonic jets, gas turbines, moon rockets, or what have you.

But lets put this steam boiler in perspective. Why was it important? Why is it important today? Why will it be important in the future? I think we can see the answers to these questions quite clearly if we just go back to our fundamentals for a moment.

When did men first begin to develop the steam boiler in earnest? Why, when they really needed energy on a scale greater than that which could be supplied by human and animal muscles. Of course, as long ago as 150 B.C., Hero of Alexandria suggested this boiler and reaction turbine, but the society of the times was not ready for it. It was not until nearly 18 centuries later, in 1629 that Branca made this drawing of an impulse turbine. By this time, however, many conditions existed which sparked the rapid development of this new source of energy: Mining for ores and minerals had expanded to a really great scale and large quantities of fuel were needed for smelting. In addition, considerable fuel was needed for space heating and cooking. Industrial and military growth, especially in England, also demanded ever greater amounts of fuel. By the middle of the 1600's forests were being rapidly denuded and it became increasingly necessary to find some other basic source of energy. Thus despite the fact that 300 years ago people were executed in England for burning coal because it produced highly noxious and dangerous fumes, the dynamics of historical growth made it essential to remove these restrictions, and coal mining began to increase.

As coal began to be mined on a large scale, mines became deeper and deeper, and were often flooded with water. The English, in particular, were faced with a very serious curtailment of their growing industrial, military and political might if they could not find some economical way to pump the water out of their coal mines. The importance that was attached to this problem can be seen from the great number of men who were working on it and by the many, many patents that were issued on machines to pump water by the use of "the expansive power of steam."

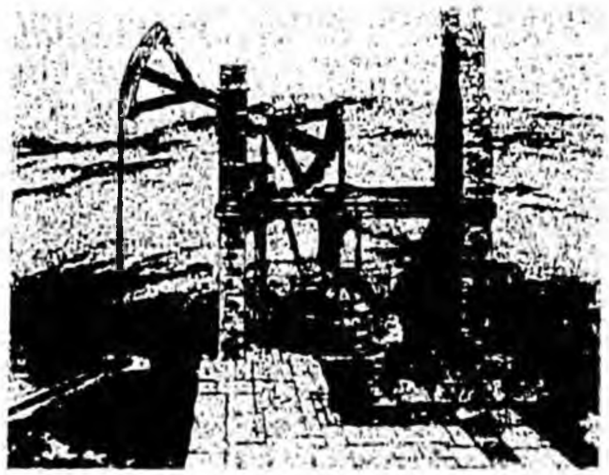
This mutual dependence of fuel and machine is not always correctly explained. It is true that the development of machinery created a demand for fuel, but it is even more significant that the need for more fuel created a demand for machinery. The early machines used wood and charcoal as fuel. Many years elapsed before the application of machine power to fuel procurement could bring production of fossil fuels up to a high enough point to displace wood.



Incidentally, these early developers were fully aware of the nature of the energy they were using. Their machines were invariably referred to as "fire engines", since it was the energy of the fire that was being harnessed and transmitted through the medium of steam.

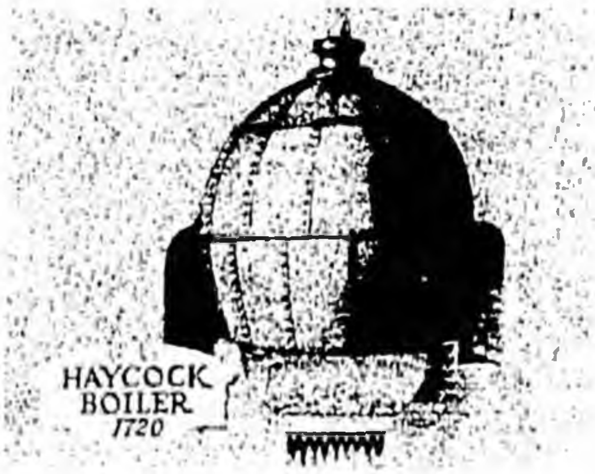
SAVERY

Savery's steam engine of 1698 used the vacuum -- achieved by alternately forming steam in a cylinder and then chilling it -- to pump water from mines. His might be considered the first practical engine, and it was actu[illegible] used in various locations.



NEWCOMEN

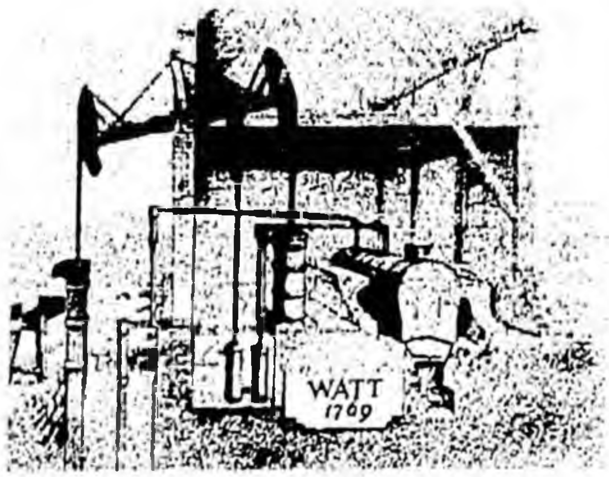
The first important development for securing useable energy through the medium of steam, however, originated with Thomas Newcomen, an iron monger living in Dartmouth, England. His first engine was based upon the concept that if steam were admitted to a cylinder in which was fitted a piston, and then a jet of water were admitted and the steam condensed, the pressure of the atmosphere on top of the piston would force the piston down the cylinder and thereby produce power which could be utilized for the then most important purpose of pumping water from coal mines.



Newcomen produced what is probably the first commercial steam engine and in 1712 had one operating in a mine at Cornwall in England. Note that the boiler for this engine - referred to as the Haycock type because of its shape -- was really a plain copper brewers kettle. Pressure was that of the atmosphere. The success of Newcomen was due to his conception of a device that would use steam at or below atmospheric pressure, thus accommodating his needs to the construction abilities and materials of the day.

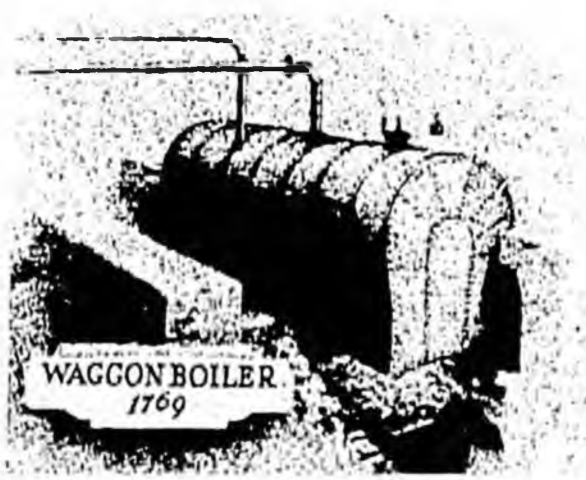
WATT

The next significant development in the steam engine came through the efforts of Watt, whose genius and enterprise really put the steam engine on the market in a large way. Watt's partnership with Bolton, who was an excellent business man with capital and machine and foundry facilities, produced a combination that brought about a very rapid development in the entire field of steam power.



Watt began his experiments with the steam engine in 1760, but commercial realization came about 1790 and this is regarded as the beginning of the industrial revolution -- only 165 years ago.

Watt's principal concept was that if the steam could be condensed in a separate shell distinct from the cylinder itself, the heat lost by the cooling of the cylinder in Newcomen's engine would be saved and that the amount of power could be increased to whatever extent pressure increase was permitted by improvements in boiler design. The condenser separate from the cylinder itself produced a saving of approximately 1/3 in the coal required for a given duty.



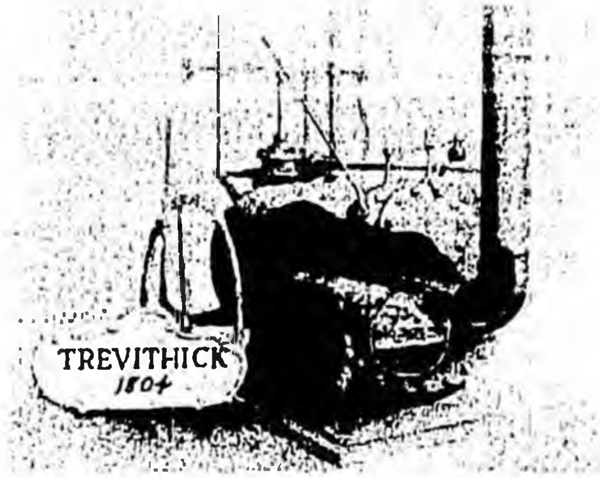
Among Watt's many contributions to engine improvement, perhaps the most important was his device to translate the reciprocating motion into a rotative motion. This development of the so-called rotative engine permitted its introduction into mills and factories where belts and pulleys could transmit the power to rotating machinery. Thus began the process of substituting energy for man's muscles -- a process still with us, and perhaps still in its infancy.

Watt's records show that he fully realized the advantage of higher pressure steam but he never built a boiler for these higher pressures and expended all of his efforts on the engine. He used the Waggon type boiler which produced large amounts of steam at about 5 pounds pressure.

Watt studied the scientific end of his problem probably more than any one who preceded him and developed tables showing the expansion of steam and changes in volume at various pressures. Incidentally, as we will discuss later, the investigation of steam properties is today an important necessity.

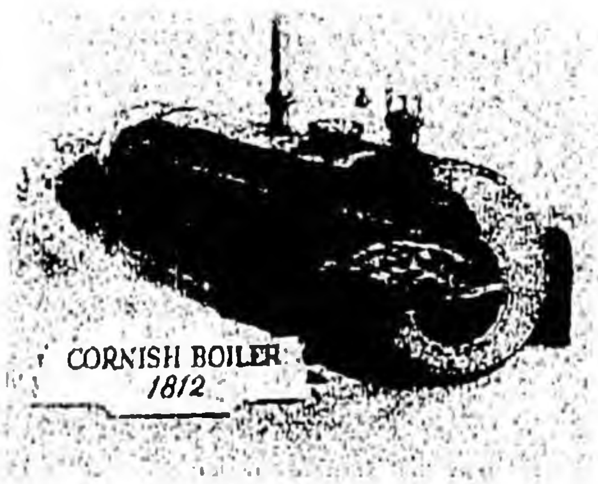
TREVITHICK

The next outstanding figure was Richard Trevithick, who as a boy of eight went to work in one of his father's mines in an English mining district. There he received as much engineering training as was available in those days, since his father was manager of several mines and thus Richard was permitted to travel from engine house to engine house and observe the pumping engines, principally of Newcomen design.



Trevithick realized the problem was still largely one of manufacturing the boiler. Whereas copper was the only material heretofore available, hammered wrought-iron plates could now be used although the maximum length was 2 ft. Rolled-iron plates became available in about 5/16" thickness in 1795.

In 1800 Trevithick made an engine for 65 lb pressure, having a 25" cylinder and a 10 ft. stroke. This same high pressure made possible the successful construction of a high pressure engine and boiler mounted together. This boiler was built in 1804 and had a cast iron cylindrical shell with the rear end dished.

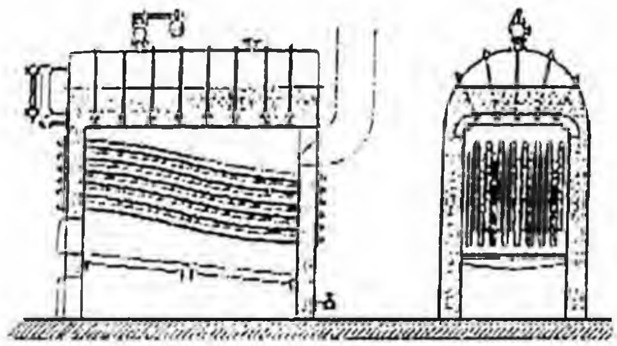


CORNISH BOILER

As the demand increased for larger and larger amounts of power, it was necessary to build larger and larger boilers, or put up with the inconvenience of a multiplicity of small units. Here is a typical Cornish boiler. Later developments saw the flue broken up by many gas tubes to increase heating surface as much as possible. This was essentially the design in widespread use up to about 1870. However, fire-tube boilers were limited in capacity and pressure. Also, because all of the steam was concentrated in one big shell, parts of which were exposed to radiant heat, they were subject to disastrous explosions.

WATER TUBE BOILERS

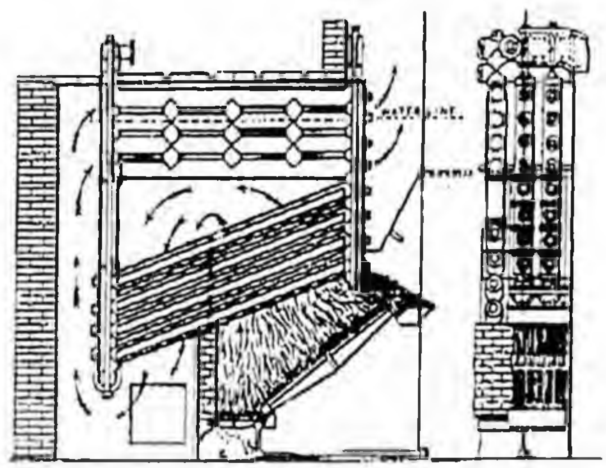
This question of boiler capacity and safety was of basic importance, and it is no exaggeration to say that for a time failure to develop adequate boilers threatened to halt industrial progress.



However, man is an inventive creature, and the moment a challenge arises, he sets to work with might and main to lick it.

The way to overcome the deficiencies of the fire tube boiler was to use a water tube boiler.

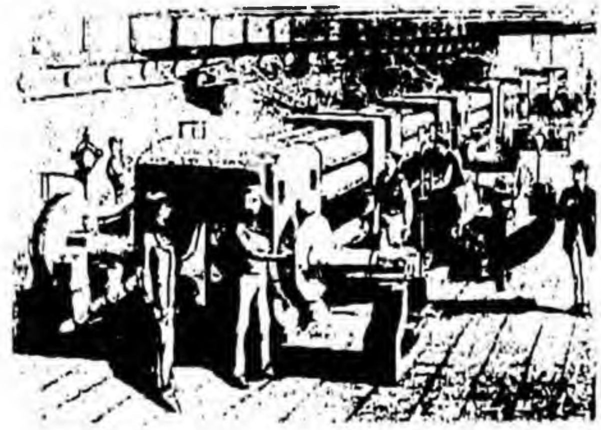
In 1856 a water tube boiler was designed and patented by Stephen Wilcox, although it was not built until several years later. The drawing shows a sinuous tube at an incline rather than a straight tube.



In 1867 Stephen Wilcox patented a straight tube boiler with tubes at 15 degree slope and arranged with handholes in the header so that there was access to the tubes for cleaning. The horizontal cast iron tubes at the top of the unit served in place of a steam and water drum. The vertical rows of inclined steam generating tubes were also of cast iron and were cast en-bloc. Internal tubes or cores were placed within the inclined tubes to aid circulation.

Stephen Wilcox clearly understood the forces involved in natural circulation. With this knowledge, he was able to design safe, economical boilers that could produce the large quantities of steam that an expanding industry needed to run its processes and improved engines.

The greater amounts of steam available from water tube boilers, their safety and increased economy thus gave a great impetus to industrial expansion in the period between 1870 and 1900. These boilers were important elements in the rapid growth of electrical generation for power and lighting.

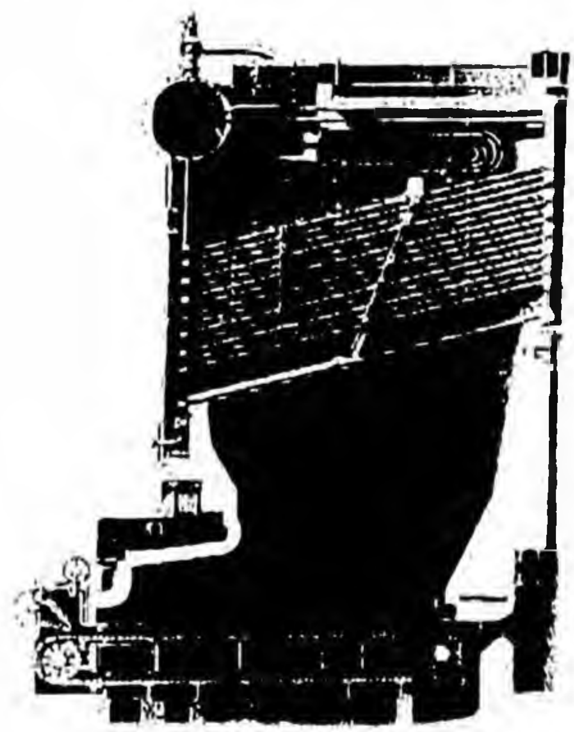


75 years ago, when Edison, using water tube boilers as his source of steam, harnessed the steam engine to the electric dynamo, he began a whole new era in energy production. At the same time, he opened up new concepts in the field of 'istribution. Two great problems were ng solved:

A) How to nufacture useable energy economically

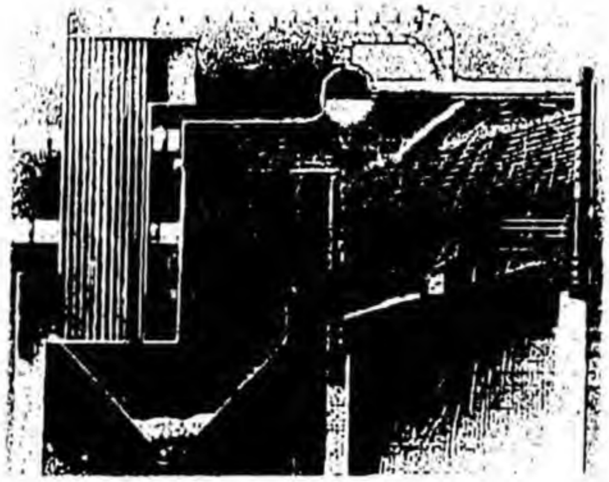
B) How to transport it cheaply and safely over great distances

We are still in the middle of this great engineering advance.

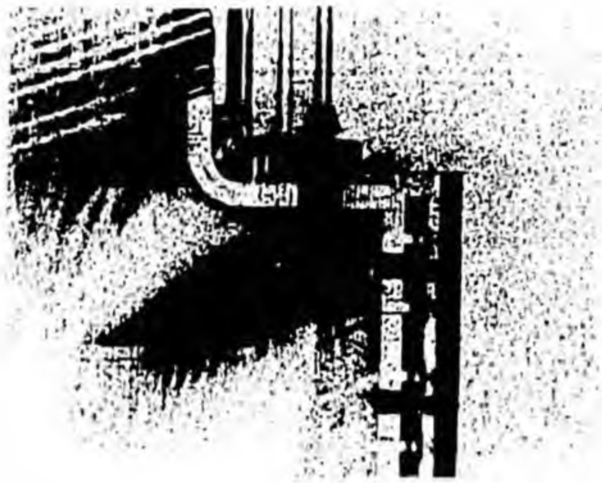


With the development and application of the steam turbine, in the early 1900's, higher steam pressures and temperatures were needed for most economical operation. Superheaters were added to boilers as a means of heating steam above the saturation temperature. To meet the demands for greater steam output, boilers were increased in size, and hand firing gave way to stoker firing.

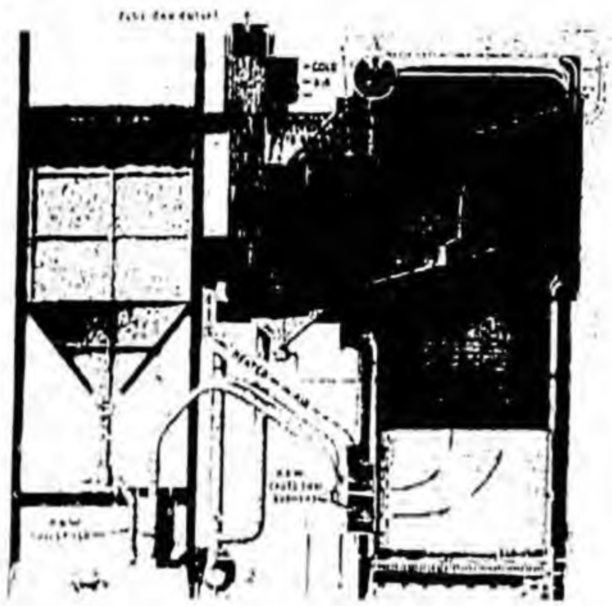
Higher steam pressures and temperatures, together with greater steam outputs, were resulting in higher heat losses up the stack. Part of these losses could be recovered by adding more boiler surface, but it was generally found to be more economical to add an economizer or an air heater, and often both. Feedwater passing through the economizer absorbed considerable heat before entering the steam drum. Preheating the incoming air for combustion greatly improved furnace efficiency. Later, in the 20's many units were equipped with reheaters, to reheat the steam after it had passed part way through the turbines, thus improving turbine efficiency.

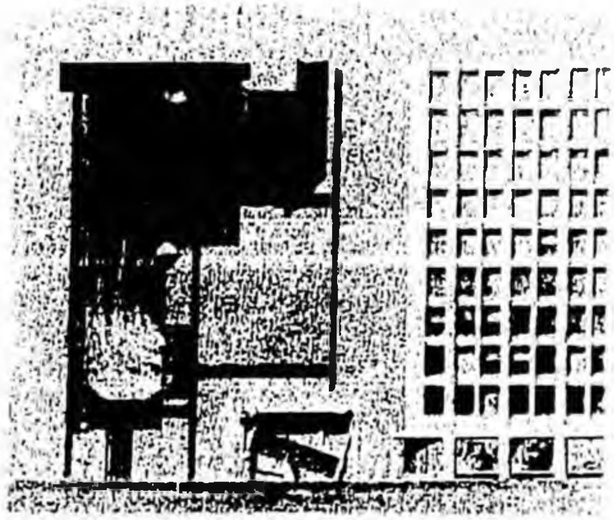


Burning coal in powdered form had long attracted the interest of boiler engineers as a means of simplifying and improving combustion efficiency. Pulverized coal-firing made rapid strides in the 1920's. Not only was efficiency improved, but a wider variety of coals could be used, and steam output was increased without excessive increases in boiler size. Early applications retained brick-lined furnaces. These were often air-cooled in an effort to reduce punishment on the brickwork. But it was evident that new types of furnaces were needed if full advantage were to be obtained from this method of firing.

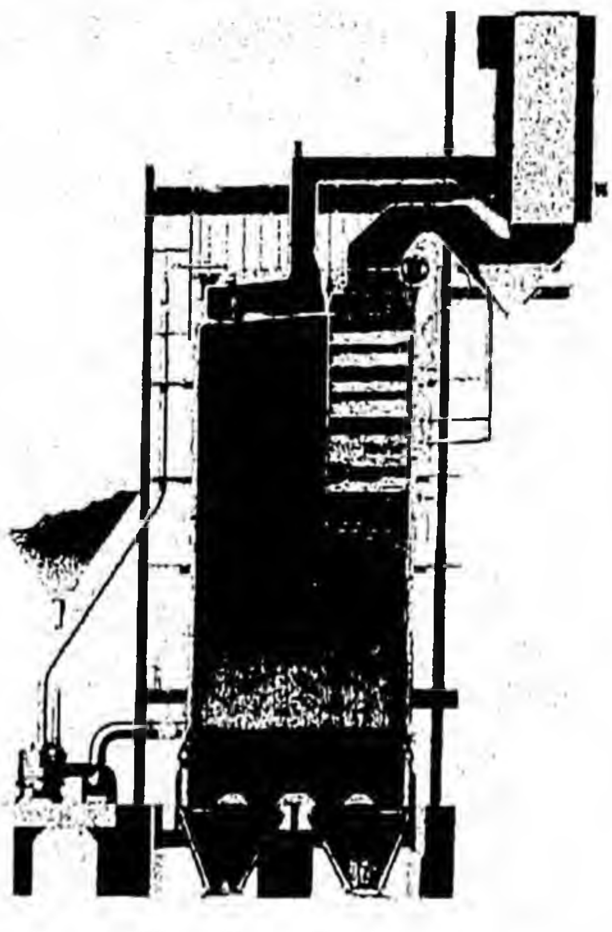


The need for improvedfurnace linings led to the development of water-cooled furnaces. Many different stages were passed through in this development, including a combination of part water-cooled and part refractory furnaces; tubes covered with metal or refractory-lined blocks; tubes embedded in plastic refractories, and bare-tubes backed with refractories. An important feature was that the tubes forming the water-cooled surface were an integral part of the boiler system, and the heat they absorbed was fully utilized to make steam.

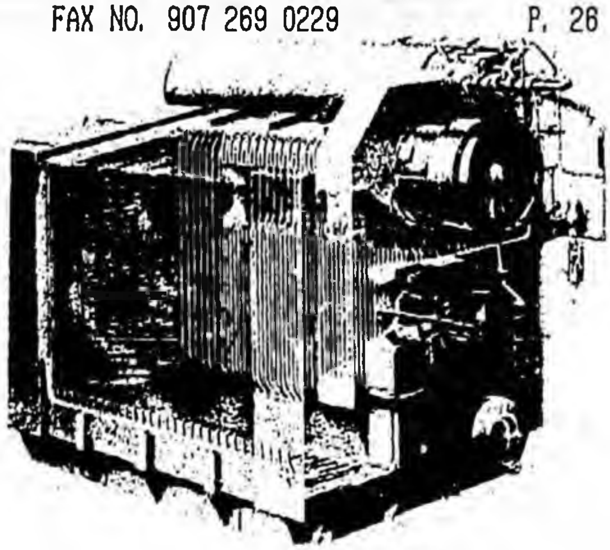




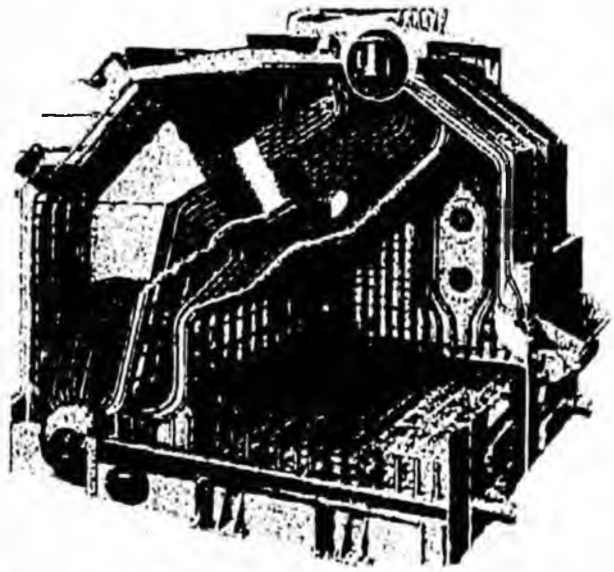
In addition to the steps outlined, progress in steam generation is being furthered by continuous work on such problems as ash and slag control; improved firing methods; metals for higher pressures and temperatures; steam purification; circulation; and many others. Thus, at the mid-point of the 20th Century, the modern central station boiler represents a great advance over the first units used by Edison 75 years ago. Its height often exceeds that of a ten-story building. Its furnace may consume as much as 20 carloads of coal per day -- and its capacity may be over 1,700,000 pounds of water evaporated, per hour. Design pressures extend as high as 2700 psi, and steam temperatures of 1100 F are becoming common.



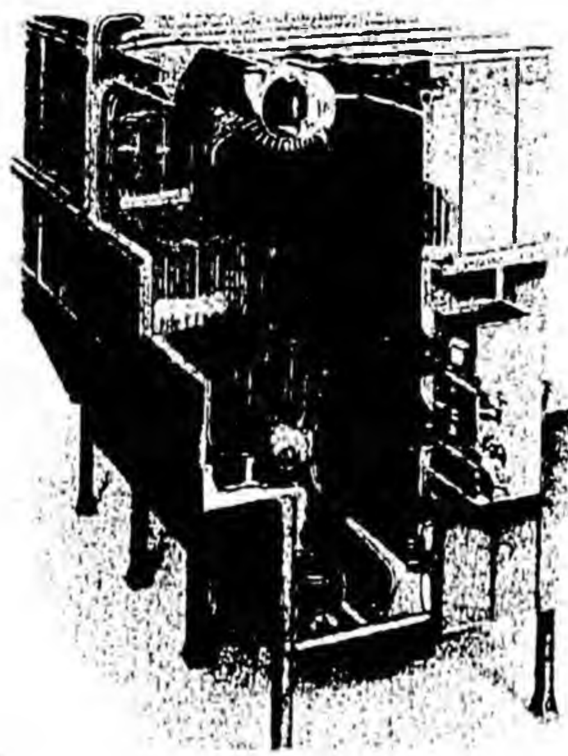
The Radiant Boiler is typical of present day central station designs. It is essentially a large water-cooled furnace with a superheater, economizer, and air heater. Reheaters are often added to improve turbine efficiency. An important feature is the high degree of reliability, so that single-boiler-per-turbine installations, with no standby units or cross-connecting piping, have become standard practice. Boilers are often not taken off the line from one year to the next, except for mandatory annual inspections.



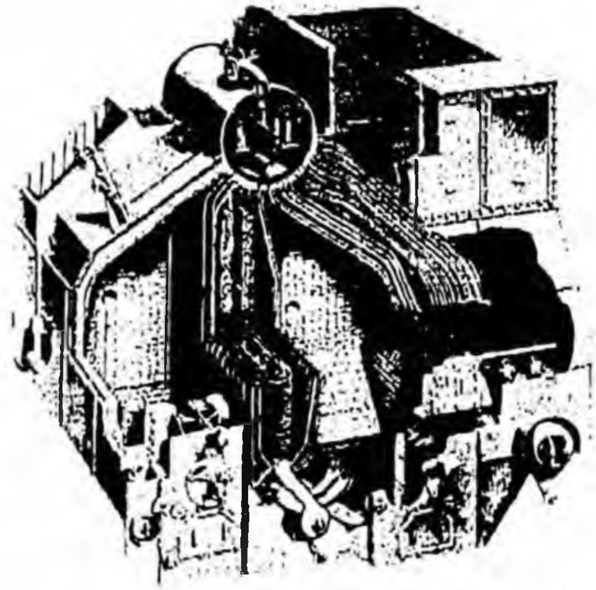
At the other end of the scale is the package unit, used for the heating and steam process needs in many industrial plants, hospitals, and large buildings. It is a fully automatic self-contained unit that is shipped completely assembled requiring a minimum of work in the field to place it in operation.



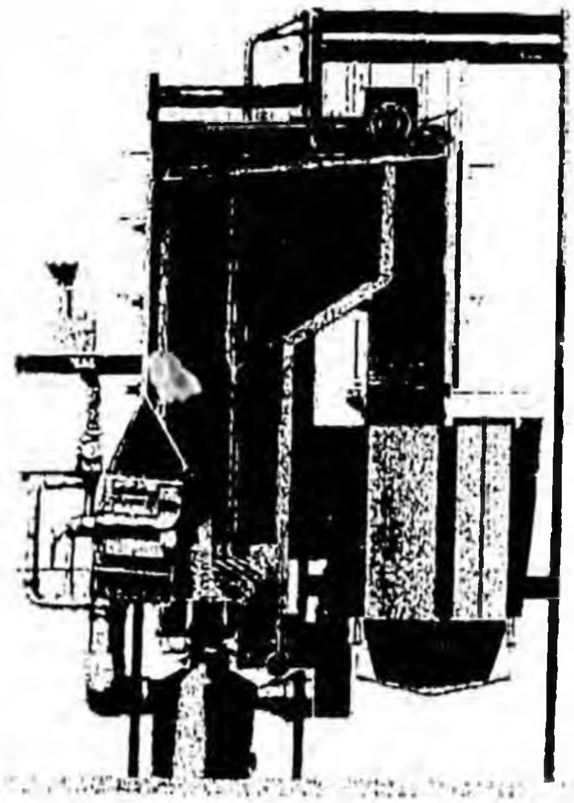
Important in modern boiler practice is the fact that the features of economy and durability developed in large central station units have also been incorporated in smaller boilers for industrial use. Typical of the units which are available for economical steam generation in the moderate-capacity range is this Integral-Furnace Boiler, which is adaptable to steam requirements ranging between 8000 pounds and 50,000 pounds per hour.



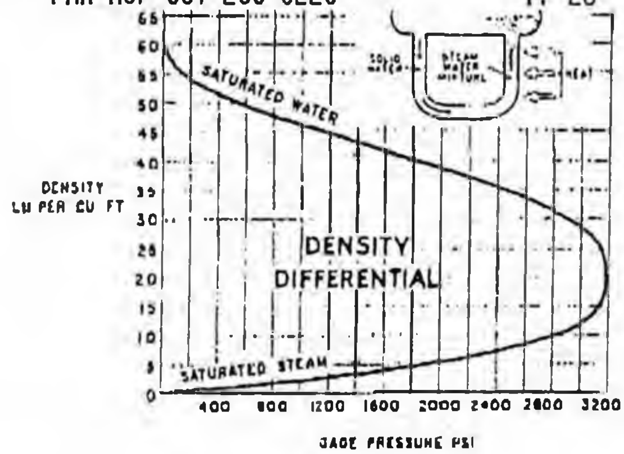
This larger Integral-Furnace Boiler, is used in large industrial plants and many central stations. It is adaptable for steam requirements up to 350,000 pounds per hour, pressures to 1150 psi, and temperatures to 910 F. The hopper bottom design contributes greater furnace cooling area, providing for a self-cleaning furnace and continuous dry-ash removal.



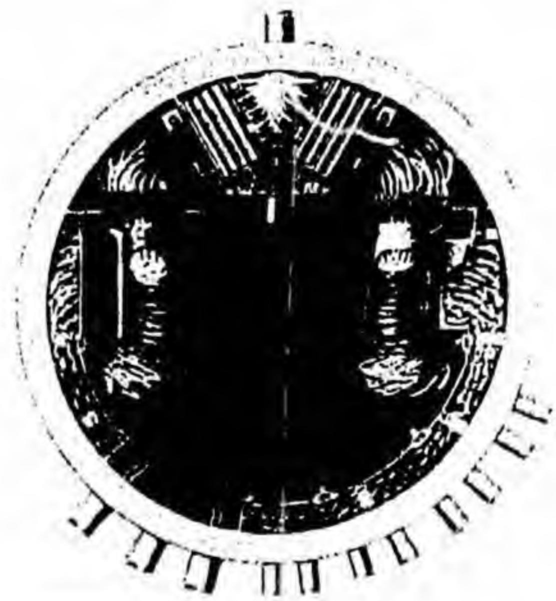
Boilers for Naval and Merchant Marine use call for special designs because of the need for compactness, lightweight, and the high degree of maneuverability required for vessels at sea and in port. The Single-Uptake, Controlled-Superheat Boiler is one of a series of designs contributing to the high degree of economy embodied in American Naval and Merchant vessels.



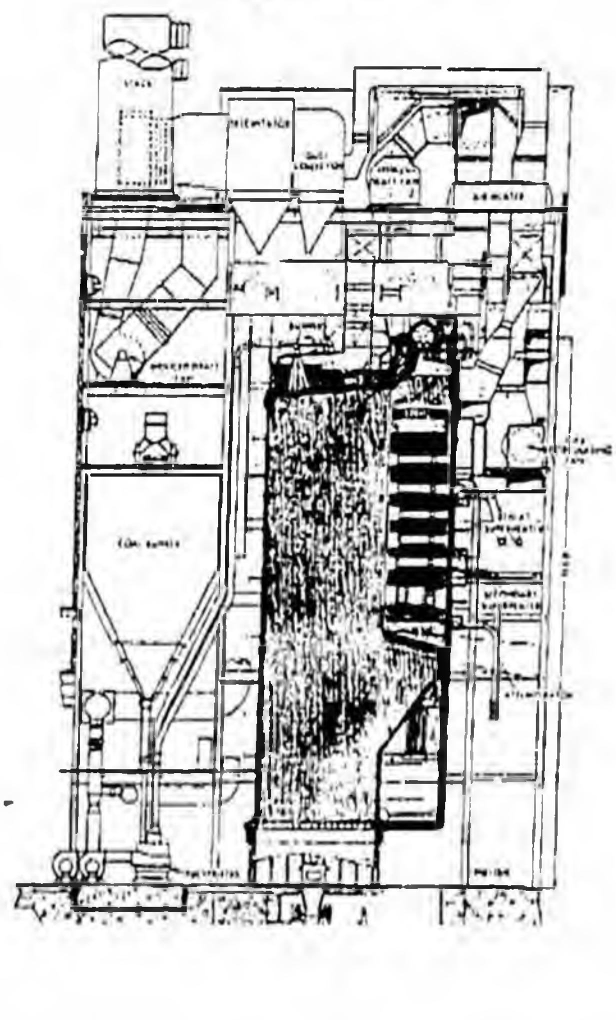
The Cyclone Furnace is typical of the manner in which constant attention to the all important matter of greater economy in steam generation is forever leading to new inventions. Crushed coal, blown spirally at great speed into the Cyclone Furnace, is embedded in a coating of slag, where it burns rapidly in a continuous blast of high-temperature air travelling at 200 mph. The Cyclone Furnace traps 90% of the ash in the form of molten slag, which can be readily drained off, and gases passing up to the stack are relatively free of fly-ash.



One important feature is common to all these units: They operate with natural circulation. No pumps are needed to force the water through the tubes. The water flows because of the differences in density between water on the one hand, and the steam-water mixture on the other. However, as water and steam pressure goes up, this density differential becomes less and less, until it disappears at the critical pressure of 3206 psi. For a while, this threatened to delay progress toward the use of higher steam pressures. However, in the mid 1930's The B&W Co., developed the Cyclone Steam Separator, which is located inside the Steam Drum. This causes the steam-water mixture to whirl in a cyclone action. Heavy, dense water is directed downward, and the light steam rises. With this device, it was possible to build boilers for natural circulation to pressures as great as 2700 psi.



So here is where we stand today. This great boiler might be taken as a symbol of progress since Stephen Wilcox first developed his water tube boiler only a century ago. It supplies steam at 2000 psi, 1050 F to run a reheat turbine generating 217,000 kilowatts. It burns 80 tons of coal an hour, which is ground in these pulverizers to talcum powder fineness. This coal is blown into a furnace which operates under pressure, another great forward step in recent years. Instead of using two fans - one to push air in, the other to draw gases out, only a forced draft fan is used. This means significant savings in construction costs, fuel costs and contributes to operating simplicity.



The steam is superheated to 1050 F and, after passing through the high pressure turbine, returns to the reheater where its temperature is again raised to 1050 F so it can do its work efficiently in the low pressure turbine. Now I toss off this steam figure of 1050 F very lightly. But did you ever think of the kinds of metals needed to contain steam at this temperature -- which is so high that the pipes carrying it actually glow in the dark? Behind that simple statements stands a whole history of technological development without which power progress would have been seriously curtailed.

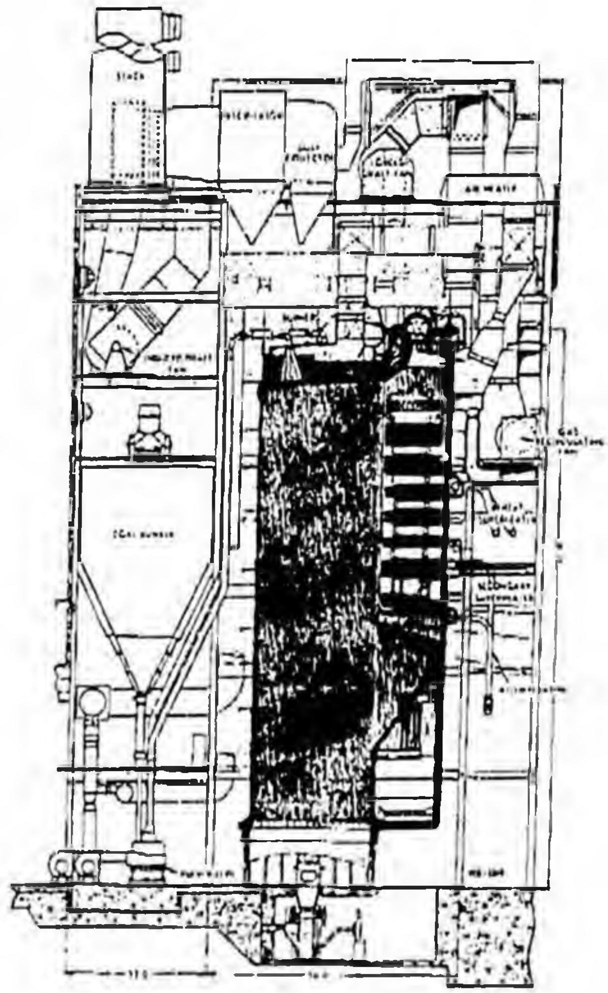
This unit has an efficiency of about 90 per cent. In other words, it is taking just about all of the heat out of the fuel that is economically possible.

This boiler and its associated turbo-generator produce a kilowatt-hour for about 9000 Btu. Only thirty years ago it took 18,000 Btu to do the same job. Surely this is a great forward step -- one of which we as boiler designers are proud -- but of which each of you as engineers can also be proud, because it is the achievement of the entire profession working with devoted cooperation that has made it possible.

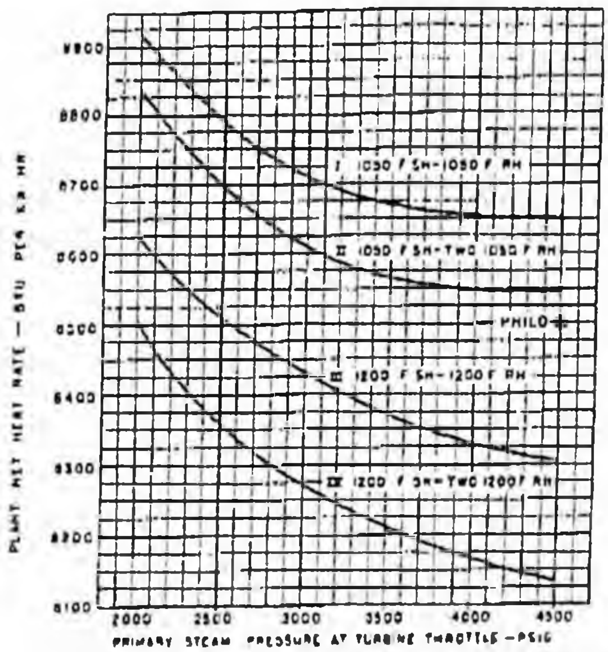
These great energy-machines are a key to the power and well-being of our nation today.

Now, I believe I have shown why steam boilers were important in the past and why they are important today. What of the future?

I would like to touch on two important developments -- one of immediate interest and the other having a longer range significance.



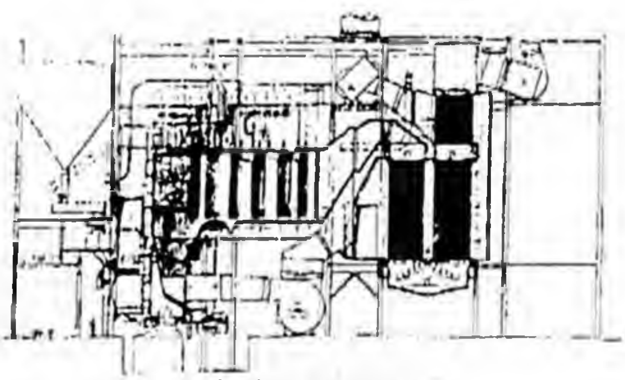
This collection of curves points out rather well the direction in which we must go for further development in conversion of energy from fuel to electricity. It shows plant net heat rates for various combinations of pressures, temperatures and reheat cycles.



EFFECT OF STEAM PRESSURE AND TEMPERATURE
PLANT NET HEAT RATE

Where the top curve intersects 2000 psi is just about where we stand today. As you can see, merely increasing pressure is not going to give as much gain in heat rate. We have to increase both the temperature and the pressure. For example, if we used 4500 psi pressure and 1200 F steam temperature, with two reheats to 1200 F, we would have a heat rate of about 8100 Btu per net kilowatt-hour. However, while we are ready with superheater and reheater alloys for these conditions, the turbine manufacturers are, very understandably, not quite ready for the entire jump. Therefore, for the next step, we are going to 4500 psi, 1150 F, with the first reheat to 1050 F, and the second to 1000 F. The heat rate for these conditions will be about 8500 Btu per kilowatt hour.

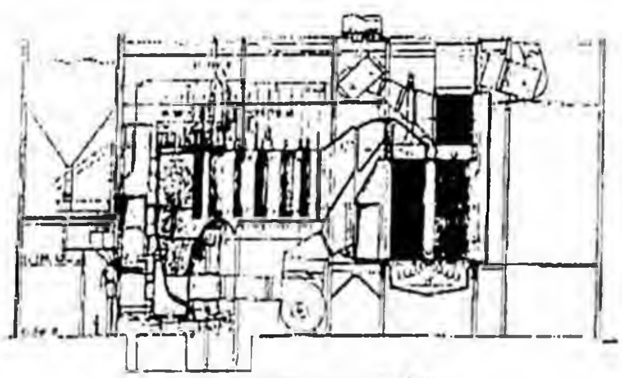
Previously we pointed out that at the critical pressure of 3206 psi, and 705 F, steam has the same density as water and therefore can no longer be separated from the water. This means that an entirely new kind of steam generator is needed. As a matter of fact, it is no longer possible to use the word boiler since water does not boil at these pressures. It instantly becomes steam.



To meet these conditions, B&W has developed the Universal Pressure Steam Generator, which can operate with equal facility both above and below the critical pressure. While this picture of the unit may seem quite complicated, you can think of it as being merely one long tube. Water enters at one end, changes to steam at some intermediate point, and becomes superheated on its way to the outlet end.

There is nothing new about this principle. Men have been working with it since at least 1824. In my own Company, we began experimental work in 1916. As the man says, the idea is simple. All that has to be worked out are the details. Believe me, the details have taken, and are taking, some working out!

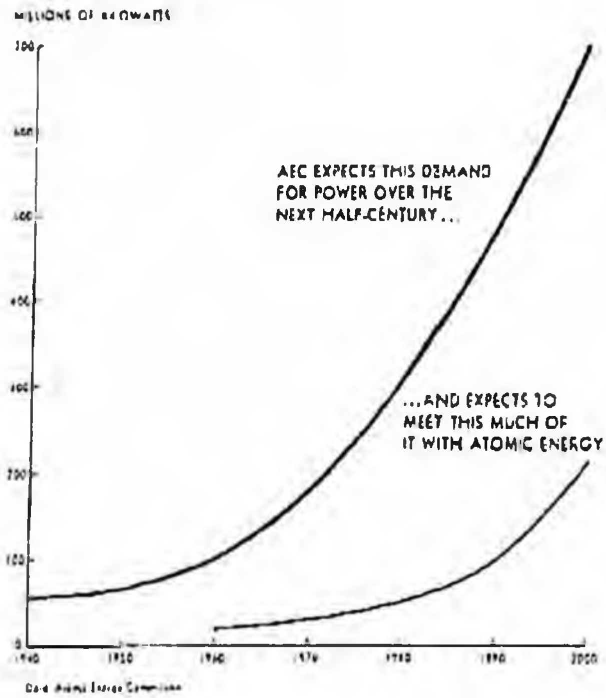
The first Universal Pressure Unit is being installed in The Philo Plant of The Ohio Power Company on The American Gas & Electric System. Fabrication has begun and it is expected that the unit will be ready for operation early in 1956. This new installation will generate 120,000 kilowatts -- three times as much as the 30 year old unit it will replace. It will fit in the same space, require little additional cooling water, and will require about 40% less fuel per kilowatt-hour. Thus will begin another entirely new era in energy conversion.



Now I know that many of you are thinking "What about Atomic Energy?" I have no doubt that when our prehistoric ancestors saw a volcano blowing its top, one or two of the less frightened, more intelligent among them might have wondered dimly how that great energy could be harnessed. As we have already seen, tens of thousands of years passed before somebody decided that steam was the way to do the job.

In the same fashion, when we saw the terrible might of atomic fission released over Hiroshima, we were anxious to know how this great force could be tamed. Again, the answer is steam or its equivalent.

Too many people without a full knowledge of the facts have been writing about the glowing benefits to be expected from Atomic Energy. And certainly there will be many blessings in the future. But as practical, every day men, charged with immediate decision, we must keep our feet on the ground and take each step carefully.

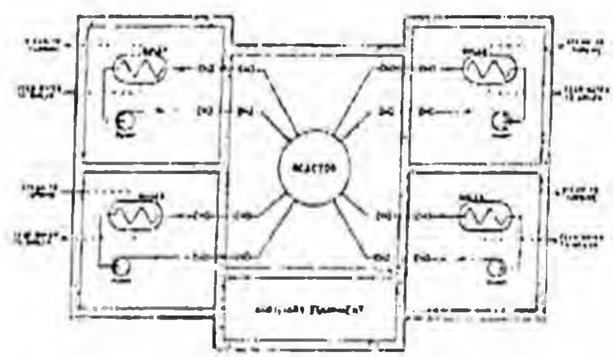


This curve shows the rate at which the Atomic Energy Commission itself expects Atomic Energy to begin to supplement fossil fuels in the development of energy. Progress may actually be somewhat faster, but this is a fair guide of what we might expect.

The question is one of economics. How much does it cost to build an Atomic plant to generate electricity compared with a fossil fuel or hydro plant? How much will it cost to keep the plant running, including cost of fuel? Because of the great technological advances I have already described in conventional power plants, Atomic Energy plants will really have to go some, especially in the U.S., to justify their cost.

Despite this, we believe the AEC is sound in going ahead with a plant to generate 60,000 kw. As you know, Westinghouse has the responsibility for this development, and the plant will be at Shippingport, Pa. on the Duquesne Light Co. system. Two of the boilers are being built by Babcock & Wilcox Company and two by Foster-Wheeler Corp.

As this diagram shows, heat from the reactor will be used to generate steam in special boilers which will supply it to conventional turbo-generator units. While the overall construction and operating costs may be high, much will be learned from this plant that will be of considerable assistance in the development of the industrial use of Atomic Energy.



I have ranged far in this discussion of the development of the steam boiler. It would not be fair to conclude without taking a look around home.

Nobody gets very far these days, industrially or domestically, if he is not close to an electric switch.

Behind that switch is a turbo-generator, a steam boiler and a sound, progressive power company that can give its customers economical, dependable service at all times.

In North Carolina, there has been a 19% population growth since 1945. In the same time, the number of electric customers has doubled.

Your great power companies, such as Carolina Power and Light and Duke, which are among the outstanding utilities in the United States, have been able both to provide this power and keep its costs within bounds, despite the great increases in cost of construction, fuel and operation.

Behind your electric switch lies North Carolina's present and future growth and prosperity, and your emancipation. "More Steam - Less Muscle".

North Carolina has grown fast in all ways

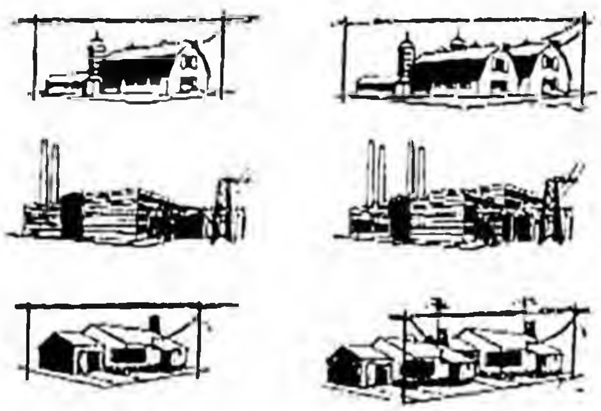
19% population growth
since end of 1945

3,467,000
POPULATION
END OF 1945

4,126,000
PRESENT POPULATION
(ESTIMATE)

North Carolina has grown fast in all ways

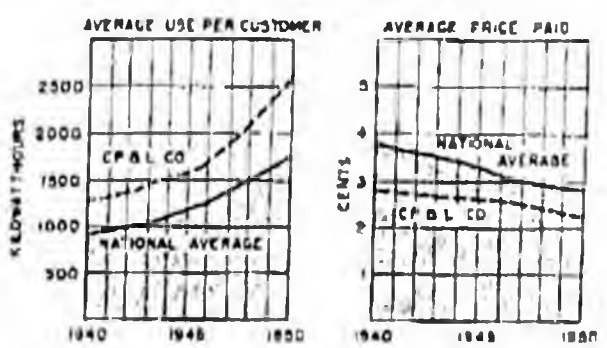
100% ELECTRIC CUSTOMER GROWTH SINCE END OF 1945



ELECTRIC CUSTOMERS
END OF 1945

PRESENT
ELECTRIC CUSTOMERS

RESIDENTIAL USE OF ELECTRICITY



HYDROCARBON PROCESSING

VOL. 70

JANUARY - JUNE

199[illegible]

JUNE 1991

Hydrocarbon Processing

Process Control

Estimate benefits
These five methods pass credibility tests

Reactor control
Fuzzy approach uses nonexact expressions

Integrated plant
Better productivity is the big payoff

Lab info system
Factors in selection outline enhancements

Oil fractionator
Modular control is now multivariable

...VATE NICKEL IN FCC FEEDS

...ANAGEMENT PREP REVISITED

...EMBRANE RECOVERS HYDROGEN

YEAR → 1991 Paul D. Kendall

Membranes recover hydrogen

Conoco uses membrane separation to recover the hydrogen that would otherwise be lost in hydroprocessing's purge stream

K. G. Shaver, Conoco Inc., Ponca City, Okla.,
G. L. Poffenbarger, MEDAL, Houston, Texas and
D. R. Grotewold, Liquid Air Engineering Corp., Houston, Texas

A MEMBRANE-BASED hydrogen recovery system (HRS) offers a simple, reliable and economical answer to the demand for increased hydrogen supply. The system can deliver a reliable supply of 95+% pure H_2 from offgas streams containing from 15% to 80% H_2. The high purity level of a membrane-based HRS allows maximum versatility in the plant use of recovered H_2. Simple, low-cost installation and an advanced, low-maintenance design contribute to HRS efficiency and economy.

An important application for the membrane-based HRS is in connection with hydroprocessing units. More hydrogen will be needed when hydroprocessing severity is increased to meet stringent government-mandated product specifications. Traditionally, the hydrogen is supplied as a byproduct from naphtha catalytic reforming, or as a primary product from steam reforming of light hydrocarbons. The HRS offers an additional supply of hydrogen by recovering the amount lost in the purge stream from a hydroprocessor's hydrogen recycle loop.

A joint venture between Dupont and members of the Air Liquide Group created the Medal membrane-based HRS.

Dupont -
Air Liquide -
MEDAL -
Conoco -

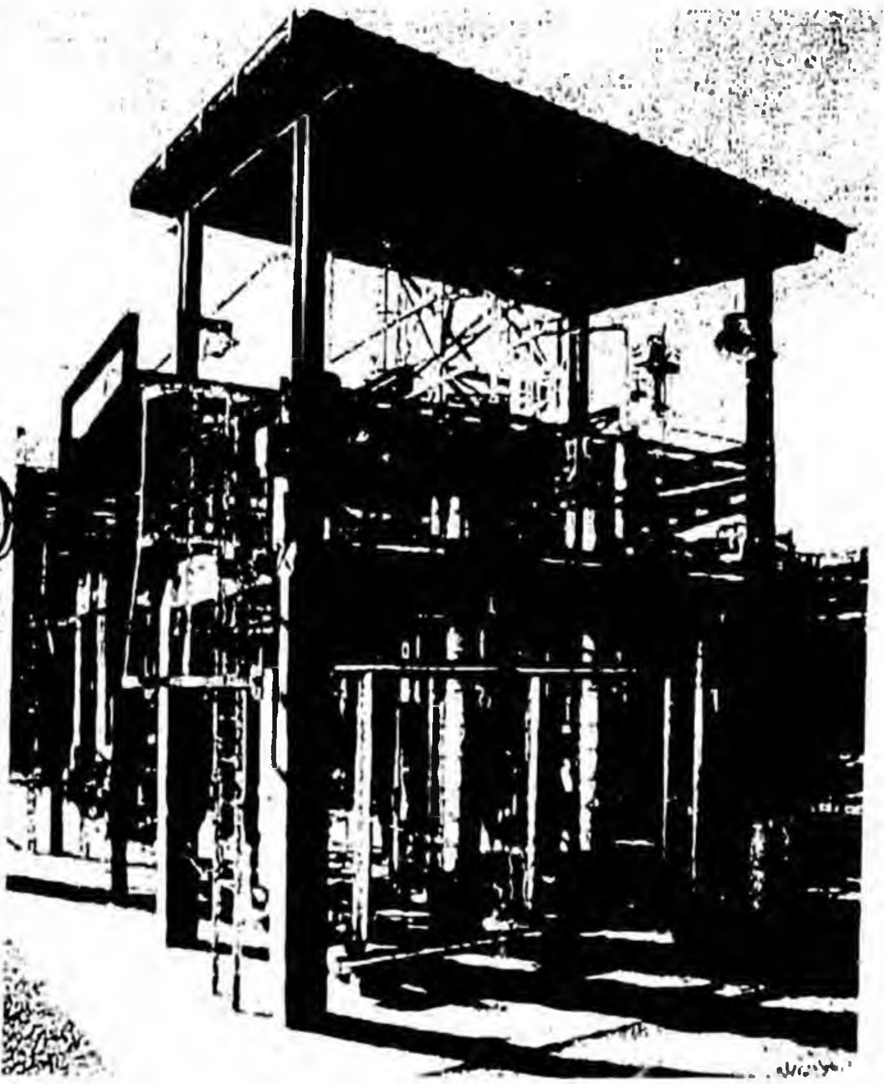


Fig. 1—View of MEDAL membrane-based hydrogen recovery system.

The process has proven reliable since its startup in December of 1987 at Conoco's Ponca City, Okla., refinery. The process proved remarkably cost-efficient: a simple payback was achieved in just 1.7 years.

The Conoco experience has demonstrated the profitability of the HRS, which continuously exceeds design specifications for hydrogen recovery, even with a feed rate variation from 8 to 20 MMscfd. A view of the HRS is shown in Fig. 1. Fig. 2 shows the historical feed and hydrogen product stream compositions and Fig. 3 shows the historical hydrogen recovery rate.

Operating benefits. The installation of a membrane-based HRS offers several inherent advantages to hydroprocessing

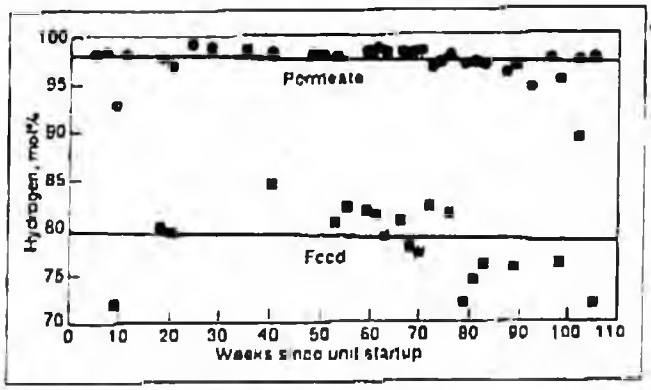


Fig. 2—Permeate retains its high hydrogen purity.

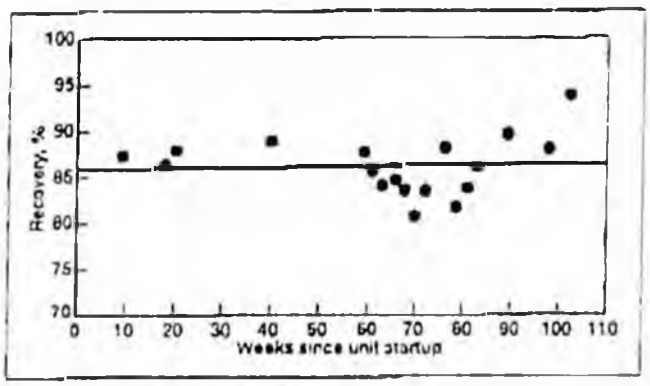


Fig. 3—Unit continues to give high hydrogen recovery.

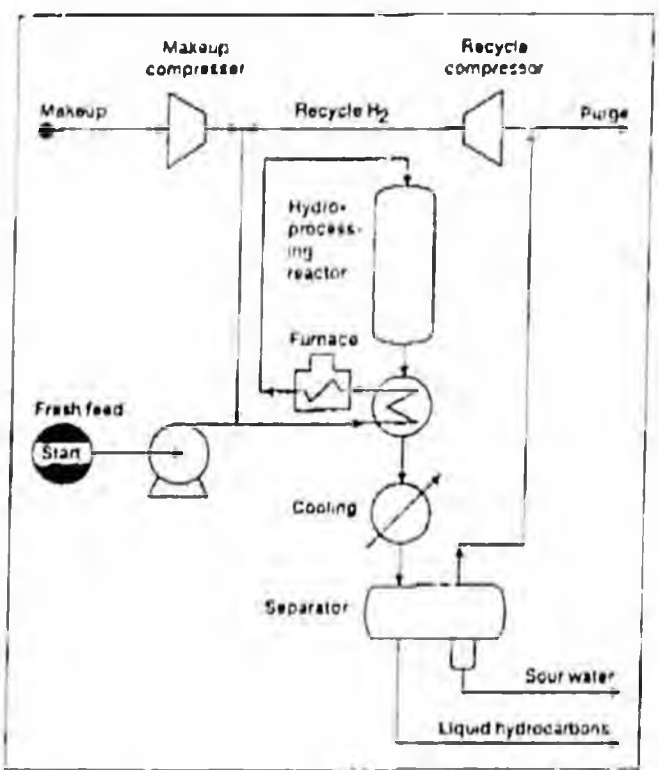


Fig. 4—Typical flow diagram for hydroprocessing.

units. Improved product quality, increased catalyst life, greater feedstock flexibility, higher productivity, incrementa hydrogen economy (the difference between hydrogen's fue gas value and its feedstock value), and reduced powe consumption have all followed the adoption of this technology.

Specific operational benefits for the Conoco commercial HRS include:

- Added value resulting from the upgrade of the coke distillate prod t from the gas oil hydrotreater (GOHDT) to higher quality gas oil.
- Decreased coking of the GOHDT catalyst due to a lowe operating temperature accompanying the higher hydroge partial pressure. Catalyst life has increased. This translates to increased run lengths and fewer turnarounds.
- Enhanced light cycle oil hydrodesulfurizer (LCOHDS productivity. Fewer passes of dark oil feed through the uni are required to meet product API and color specifications.
- Longer times between regeneration of the LCOHDS uni due to the decreased operating severity possible through us of higher hydrogen concentration in the unit.
- Decreased energy consumption in the GOHDT makeu compressor due to recycle of the LCOHDS purge. The highe hydrogen purity stream allows lower volumetric flowrates makeup gas to be compressed.

In comparison to other hydrogen recovery systems, th Conoco refinery HRS has minimal utility and maintenanc costs. Utilities include low-pressure waste steam for the fee preheater, electricity for heat tracing on piping and vessel during HRS inactivity and instrument air. Maintenance fo the membrane system has been limited to routine inspections recalibration of instruments and filter element change out The onstream efficiency of the HRS has equaled the feed ga availability.

Table 1 identifies the quantifiable economic benefits of th HRS.

TABLE 1—HRS economics

Investment, $	662,000
Debits, $/yr	
Steam consumption	22,000
Lost hydrogen fuel value	75,000
Maintenance and overhead	29,000
Total	126,000
Credits, $/yr	
Gas oil HDT product upgrade	396,000
LCO HDS product upgrade	74,000
Reduced power consumption	42,000
Total	512,000
Earnings, $/yr	386,000
Simple payback period, yr	1.7

TABLE 2—Typical hydroprocessing unit operating conditions

Operating temperature, °F	500–800
Operating pressure, psig	100–3,000
Chemical hydrogen consumption, scf/bbl of feed	200–2,000
Purge stream hydrogen content, mol%	60–90

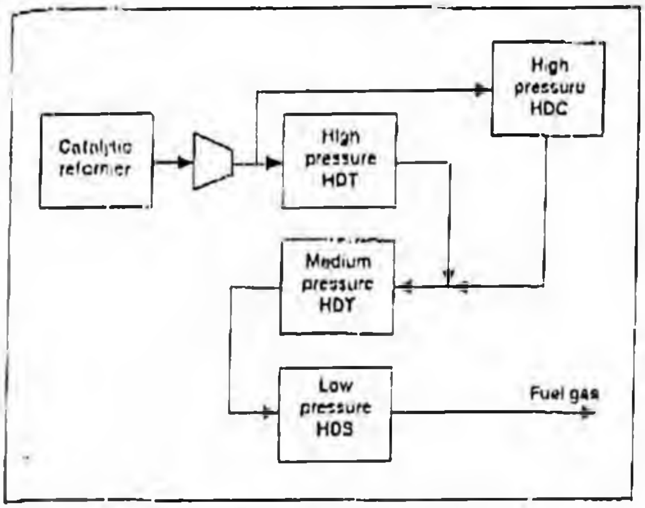


Fig. 5—Hydrogen shared among several refinery units.

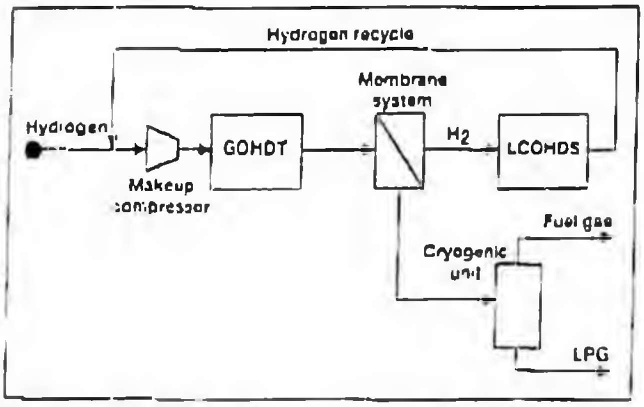


Fig. 6—Membrane system added between two treating units.

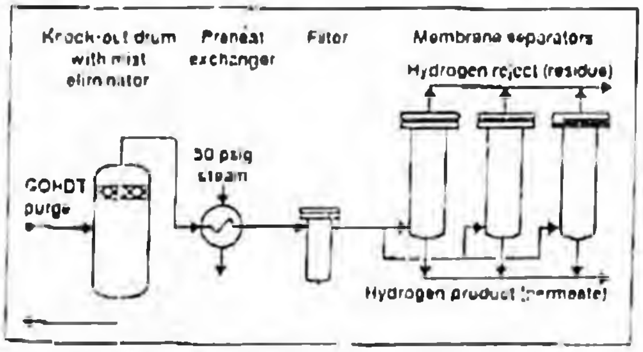


Fig. 7—Flow diagram of hydrogen recovery system

Hydroprocessing background. Hydrogen consumers such as hydrotreaters, hydrodesulfurizers and hydrocrackers remove impurities and upgrade low-value distillate streams to more valuable feedstocks or products. The severity (temperature and pressure required to accomplish the conversion process) of a hydroprocessing unit varies with the conditions of the feedstock. High-pressure hydrocrackers are often used to convert higher boiling point materials into motor fuels, lower pressure hydrotreaters catalytically stabilize or remove objectionable elements from petroleum products or feedstocks. Table 2 and Fig. 4 show typical hydroprocessing conditions and a typical flow scheme.

In the hydroprocessing unit, hydrogen is combined with the fresh feed and heated before being fed to the hydroprocessing reactor. In the reactor, hydrogen is consumed in desulfurization, hydrogenation, hydrocracking and other side reactions. Unconsumed hydrogen is separated from the reactor liquid products and recycled back to the reactor. The recycled hydrogen is combined with fresh makeup hydrogen prior to being fed to the hydroprocessing reactor. A portion of the recycled hydrogen is purged to prevent inert buildup.

Most refineries amine-treat the recycle stream to remove undesirable sulfur compounds and then take advantage of the pressure energy contained in the purge stream by using it as makeup hydrogen for lower pressure hydroprocessing operations. Fig. 5 shows an integrated refinery hydroprocessing hydrogen system.

The high-pressure hydrogen purge stream from a hydroprocessing unit is an ideal candidate for hydrogen recovery. With membrane technology, hydrogen separation is driven by a partial pressure difference. The recovered hydrogen can be returned to the hydroprocessing unit reactor loop as makeup or used as a high purity hydrogen stream for other hydroprocessing applications.

Hydrogen partial pressure is a key design and operating consideration for a hydroprocessing unit. For new hydroprocessing units, the hydrogen partial pressure required to achieve the desired conversion directly affects equipment sizes, pressure classifications and costs. Incorporating membrane-based HRSs into the design of new hydroprocessing units keeps operating pressure at an economic level.

In existing hydroprocessing units, hydrogen partial pressure directly affects operating severity, compression costs and liquid thruput. Installation of a membrane-based HRS reduces operating costs and/or increases liquid thruput by raising the hydrogen partial pressure in the reactor.

A membrane-based HRS was the preferred technology to recover high purity hydrogen from Conoco's GOHDT purge by using the available pressure drop to the LCOHDS.

Previously, at Conoco's Ponca City refinery, a GOHDT high-pressure purge stream, containing 71 mol% hydrogen, fed the LCOHDS and the cryogenic liquified petroleum gas (LPG) recovery unit. The purge stream was let down from the GOHDT to the LCOHDS and used on a once-through basis in the LCOHDS before being purged to the fuel system.

Conoco's design specification for the HRS was to produce a stream containing 95 mol% hydrogen from the GOHDT high-pressure purge stream (75% recovery of hydrogen). The available pressure drop from the GOHDT to the LCOHDS provided the driving force for the membrane separation. Fig. 6 illustrates the present GOHDT-LCOHDS system.

The HRS hydrocarbon product stream is sent to the cryogenic recovery unit for recovery of LPG. The hydrogen product from the HRS is sent to the LCOHDS and, again, used on a once-through basis. Because of the high purity of the hydrogen feed to the LCOHDS, the LCOHDS offgas remains 90+ mol% hydrogen. The high purity of the offgas allows for optimum hydrogen utilization by recycling this stream to the GOHDT makeup compressor. The addition of this recycle effectively increases the capacity of the membrane unit.

Design philosophy. The feed pretreatment section contains a knockout drum, a feed preheater and a dry gas filter. Feed gas enters the pretreatment section at the knockout drum to

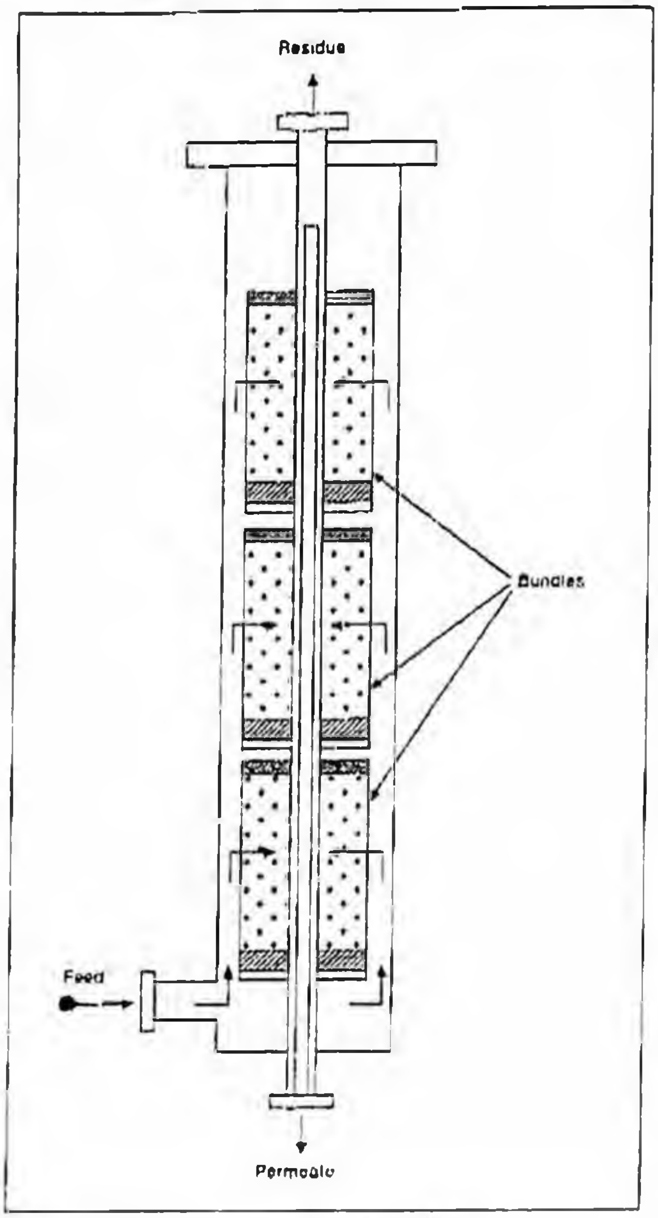


Fig. 8—Permeator uses radial crossflow separation.

eliminate liquid slugs and remove entrained liquid droplets. The feed gas then passes through the preheater to provide superheat, and finally to the dry gas filter to remove any particulates before entering the membrane separation section. Fig. 7 shows a flow schematic of the HRS.

At the membrane separation section, the gas is distributed for processing into three permeator vessels. The permeators use hollow fiber membranes configured in a radial crossflow pattern as illustrated in Fig. 8. The 12-inch diameter commercial bundles resemble filter cartridges and consist of a collection of millions of hollow fibers formed together for installation into a permeator vessel.

Feed gas enters the side of the permeator vessel, is distributed into the annulus between the fiber bundle and the vessel wall, and continues to flow radially inward. As the feed gas contacts the hollow fibers, the more permeable hydrogen diffuses through the wall of the hollow fiber and is carried through the fiber bore, exiting the fiber at a lower pressure. The less permeable hydrocarbons flow around the fiber walls to a perforated center tube, exiting the permeator at approximately feed pressure.

The HRS was designed for maximum flexibility and on-line reliability. The pretreatment section was designed to handle 150% of the normal feed flowrate and the membrane separation section was sized to surpass design specifications. The feed gas preheater is a hairpin type exchanger which is specified for compactness and uses waste steam. It is operated as a flooding condenser. Unit capacity can be easily increased by connecting additional membrane separators in parallel to the existing separation skid.

The HRS is designed as a modular, skid-mounted unit. The Conoco Refinery's HRS consists of two sections: a feed pretreatment skid and the membrane separation skid. The installed unit encompasses an area of approximately 12 feet by 50 feet.

Conoco refinery personnel's experience in hydrotreating operations was used to establish the design and integration of the HRS. For example, since the amine contactor used to treat the COHDT purge stream had a history of foaming and carrying over liquid slugs downstream, design specifications included a knock-out drum with a mist eliminator pad and liquid level control as protection for the recovery system.

The membrane performance parameters were evaluated and quantified at a pilot facility also located in Conoco's Ponca City refinery. The pilot facility is highly instrumented and computer-controlled for real-time data acquisition from multiple commercial scale membrane bundles. Tests, using actual field gas streams with compositions ranging from 18 to 80 mol% hydrogen and pressures up to 1,100 psig, led to the development of a computer model and performance maps for this membrane system.

Summary. Conoco's Ponca City refinery substantially reduced the capital investment requirement for recovering hydrogen by installing hydrogen membrane technology. A comparison of hydrogen recovery and purification technologies indicated that the hollow-fiber membrane was superior for this application. Low capital investment, low utility costs, high hydrogen recovery, consistent hydrogen product purity, minimal maintenance costs and high flexibility support the MEDAL HRS alternative. ■

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Susitna Hydroelectric Project
FUTILE QUEST FOR A PLAN OF FINANCE

by Gordon S. Harrison

IN ALASKA two contemporary large-scale engineering projects are noteworthy. One is the development of North Slope oil resources, including construction of the trans-Alaska pipeline. This impressive achievement is the work of private companies and private capital. A second important contemporary megaproject in Alaska is one planned by a public agency of the state – the Susitna hydroelectric project. Planning activity on this project was recently suspended, and the current prospect for its revival is not good. Despite the unhappy fate of this project (or perhaps because of it), the Susitna project is an interesting case study of public sector planning for a major infrastructure development project.

This article considers only the financial aspect of the Susitna project. As it happens, this is the critical dimension, because the failure to devise a workable and acceptable financing plan led to the project's demise. In this paper I will review the history of financial planning for the project from 1982 (date of completion of the feasibility study) through March of 1986, when the project was put on the shelf. The objectives of this review are to explain why a workable plan of finance was so elusive and, more important, to seek insights from the history of the Susitna project that may benefit future planning for major energy projects.

PROJECT DESCRIPTION

The Susitna hydroelectric project was to include two dams along the Susitna River in the Talkeetna Mountains of southcentral Alaska. When completed, the project would have a combined installed capacity of 1620 megawatts and an average annual energy yield estimated at 6200 gigawatt-hours.

The Watana Dam, intended for operation in 1996, was to be a rock structure 886 feet high and 4100 feet long, capable of generating 1020 megawatts. At this height, Watana would be the fifth highest embankment dam in the world, and the highest in North America, exceeding the Mica Creek embankment dam in British Columbia (794 feet) and the Oroville Dam in California (771 feet). The Watana reservoir would extend upstream 48 miles; it would be 1 to 5 miles wide, and it would have a maximum depth of 680 feet.

The Devil Canyon Dam, located 32 miles downstream from Watana, was scheduled to be operating by 2002. It was to be a double-curved concrete arch 645 feet high and 1500 feet long, capable of generating 600 megawatts. The dam's height would include it among the nine tallest arch dams in the world, including the Hoover Dam in Arizona (725 feet) and Inguiri in the Soviet Union (892 feet). The reservoir for Devil Canyon would be 26 miles long, ½ mile wide at its widest point, and have a maximum depth of 550 feet.

ALASKA POWER AUTHORITY

In the United States, major public sector infrastructure projects are typically built, owned, and operated by quasi-independent public corporations. So it is in Alaska, where the Susitna project is under the jurisdiction of the Alaska Power Authority (APA). The APA is a public corporation governed by a board of directors appointed by the governor of Alaska. It has its own professional staff but relies heavily on consulting firms to provide engineering and other technical expertise.

APPROACHES TO STATE SUBSIDIZATION

Large infrastructure projects that are developed by public corporations usually rely on the sale of revenue bonds for financing. Revenue bonds are debt issues (the interest on which is usually exempt from state and federal taxation) sold in the national capital markets that are secured by income generated by the project (road tolls, electricity sales, gate receipts, and other fees charged to users of the project).

However, Susitna was such a large, expensive project that it could not be financed exclusively by conventional revenue bonds. Payment of interest and principal on revenue bonds sold to cover all project costs would result in an exorbitant price for electricity in the early years of the project. Therefore, it was always assumed that the State of Alaska would need to subsidize the project.[1]

Two forms of state subsidy for Susitna were proposed during the course of project planning. One was referred to as state "equity" investment in the project. In this case, state appropriations would be used to pay some or all construction costs, and thereby reduce or eliminate altogether the requirement for borrowing. The second form of state subsidy was referred to as "rate stabilization." In this case, state appropriations would be used to help make

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payments of principal and interest on revenue bonds. Thus, state subsidy would be used to service debt rather than reduce the overall amount of debt.

State subsidy to the project in the form of loans was among the financing mechanisms considered by project planners, but loan alternatives were never fully developed and incorporated into financing plans for Susitna.

The two main financing concepts of equity and rate stabilization can be illustrated graphically. Line AE in Figure 1 represents the real wholesale price of electricity from a large, hypothetical hydroelectric project that is financed entirely by debt. This line gradually slopes downward to point E because hydro projects are typically built to accommodate load growth (resulting in lower unit costs), and because of the effect of inflation on level nominal debt service. At point E, the initial debt is retired and the price of power thereafter is based on operation and maintenance costs.[2]

Line BD in Figure 1 represents the projection of wholesale electricity prices that would prevail without the hydro project. In the case of Susitna, this line represents the wholesale price of power in the Railbelt from gas- and coal-fired thermal plants. This projection assumes real price increases due to rising fossil fuel prices and other costs of operations.

Line BF in Figure 1 represents the wholesale price of electricity from the hydro project with a combination of revenue bonds and state equity. In this case, the size of the state's equity investment reduces the amount of debt to that level which produces an entry price of power from the hydro project equal to the price of power from the thermal alternative (point B). Increasingly larger equity investment in the project would further reduce the price of hydropower. If the project were entirely financed by cash grants from the state—100 percent equity financing—the wholesale cost of power would not have a debt service component, and it would represent the variable costs of operation and maintenance only (this scenario is not shown in Figure 1).

Figure 2 illustrates how rate stabilization works. Here, state contributions to the project do not reduce the amount of debt; rather, they reduce the price of hydropower (line AC) to the level of the thermal alternative (line BC) until the two are the same (at point C). Customers will pay for electricity along the line BC, with the state making up the difference through rate stabilization. At the crossover point C, hydropower becomes cheaper than the alternative, and no further subsidy is required (customers then pay along the line CE). An underlying assumption of this approach is that customers will not be willing to pay more than they would otherwise pay for electricity, notwithstanding future savings that the project will create.

It is evident from the relative size of the shaded area in these two figures that less state subsidy is involved with rate stabilization than with the equity approach (on the basis of the general assumptions underlying these curves). Also, it is no doubt evident that utility customers would prefer to pay along the line BF in Figure 1 than BCE in Figure 2.

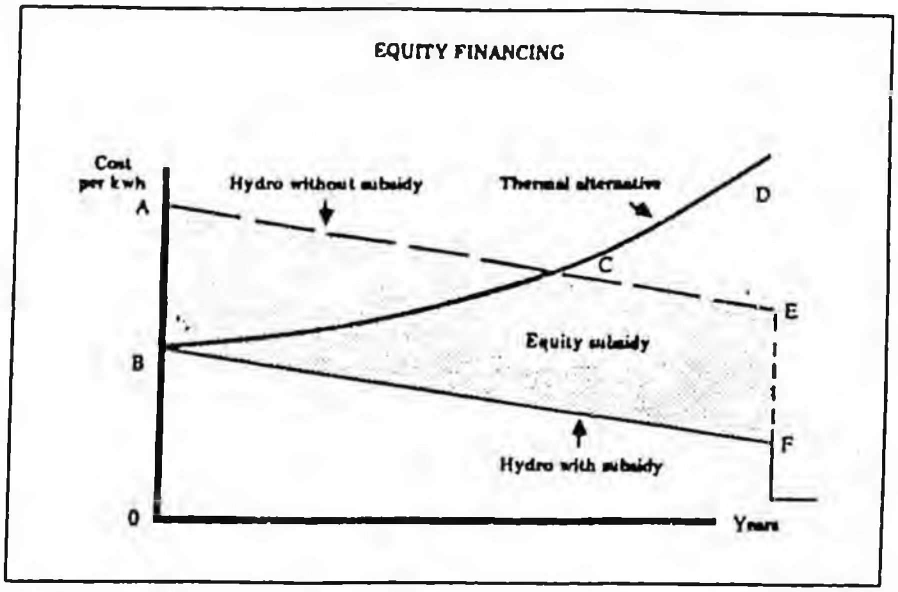

Figure 1. Providing state subsidy in the form of equity reduces the requirement for debt financing. In this figure, the shaded area represents the amount of equity needed to make the wholesale price of hydropower equal to the wholesale price of power from the thermal alternative.

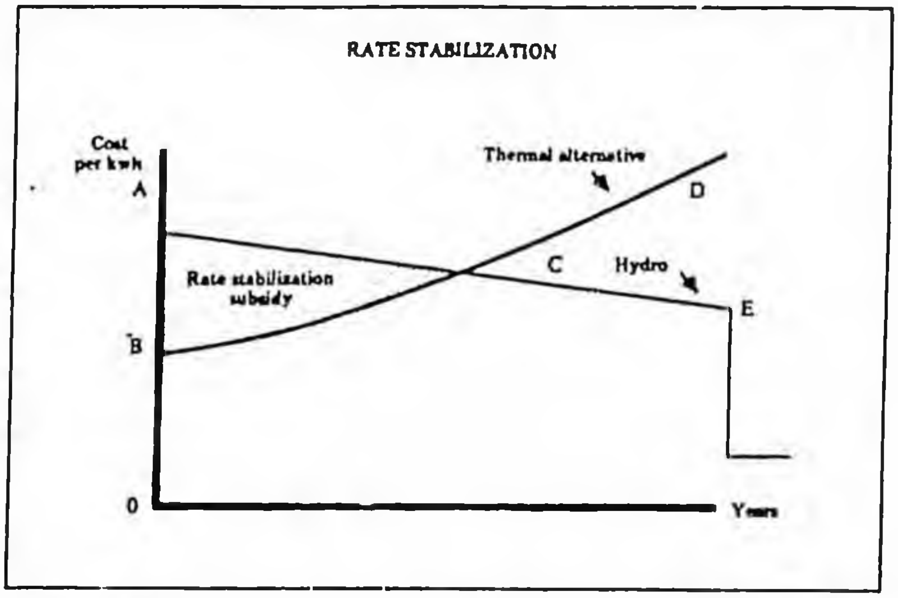

Figure 2. Providing state subsidy through rate stabilization requires utilities to pay for hydropower along the projected curve of the thermal alternative until the crossover point C is reached. This financing approach is more desirable than the equity approach from the state's point of view.

REAL AND NOMINAL DOLLARS

Because of the long time involved in debt repayment, it is necessary to account for the effects of inflation when analyzing the cost of any major project. Thus, finance planners and economists distinguish between real (or constant) dollars, which exclude inflation, and nominal dollars, which include the effects of inflation. In those terms, the cost of the Susitna project was estimated to be about $5 billion at prices prevailing in 1985 (real dollars), but more than $12 billion at the prices prevailing when the expenditures actually would be made (nominal dollars).

REVIEW OF FINANCE PLANNING

A review of finance planning for the Susitna project is best approached chronologically, beginning in 1982 when a major feasibility study was completed.

1982

In 1982 a feasibility study of the project was completed and three financing options proposed. During this time, however, the long-term oil price outlook was deteriorating.

Acres American report. In March 1982, the firm Acres American released a major feasibility study of the Susitna project. The firm had been under contract to the APA since late 1979. The Acres American report proposed the two-stage construction schedule described above under "Project Description." This project configuration and the supporting analysis became the basis for APA's license application to the Federal Energ, Regulatory Commission (FERC).

With regard to financing, the Acres American report proposeu three options: (1) 100 percent state appropriation of the total cost of construction, estimated to be $5.1 billion in 1982 dollars; (2) a state appropriation of $3 billion (1982 dollars), with the remaining project cost financed with revenue bonds; or (3) a minimum state appropriation of $2.3 billion (1982 dollars) with the remaining project cost financed with revenue bonds. (The Acres American and other major financing proposals are summarized in Table 1.) It is noteworthy that one of the financing options was a cash grant from the state for the full cost of the project. At this time, it was widely presumed that Alaska's statewide hydroelectric development program would be funded entirely by state grants.

The other two financing options .re variations of the equity approach shown in Figure 1. An equity contribution of $3 billion would represent an entry rate for the project somewhat below point B in the figure; an equity contribution of $2.3 billion was calculated to represent an entry rate at point B (i.e., at a price equal to the

Table 1. Finance Plans for the Susitna Project

Report[1]	Total costs (billions) Constant $ Construction	Nominal $ Construction	Nominal $ Financing	Nominal $ Total	Revenue forecast	Finance options Constant $ (Same year as "Constant $" column)
Acres American Feasibility Study (Mar. 1982)	5.1 (Jan. 1982 $)	15.3	0.0	15.3	Battelle Report[2]	1. 100% state appropriation of total capital cost ($5.1 billion). Consistent with SB25.
		15.3	1.6	16.9		2. State appropriation of $3 billion with residual bond financing.
		15.3	1.7	17.0		3. Minimum state appropriation of $2.3 billion with residual bond financing.
FERC License Application (Feb. 1983)	5.1 (Jan. 1982 $)	15.3	2.0	17.3	Battelle Report	State appropriation of $1.8 billion with residual bond financing.
Kentco Report for the Anchorage Chamber of Commerce (Jan. 1984)	5.1 (1983 $)	13.4	3.4	16.8	DOR mean Sept. 1983	State appropriation of $800 million in equity and $778 million in rate stabilization. Remaining financing requirements met by combination of REA guaranteed loan and municipal bonds.
APA Economic and Financial Up-date (Feb. 1984)	5.4 (Jan. 1983 $)	11.8	5.2	17.0	DOR mean Dec. 1983	1. State appropriation of $1.5 billion in equity and $400 million in rate stabilization funds (RSF).
		11.8	4.4	16.2		2. State appropriation of $1.7 billion in equity and $350 million in RSF, plus an REA-guaranteed loan of $1.5 billion, with residual bond financing.
Draft FERC License Amendment (Nov. 1985)	5.4 (Jan. 1985 $)	12.7	7.8	20.5	DOR mean June 1985	State appropriation of $220 million for rate stabilization, with revenue bonding of full project cost.
APA Draft Plan of Finance (Jan. 20, 1986)	5.4 (Jan. 1985 $)	12.7	7.8	20.6	Not stated	State to provide $520 million for rate stabilization by appropriation or pledging earnings from the Permanent Fund. $2 billion (nominal $) of project revenue bonds to be secured by Railbelt utilities. Residual bond financing issued by state and secured by Permanent Fund earnings.

[1]All reports are available at the Alaska Power Authority, Anchorage.

[2]Alaska economic projections for estimating electricity requirements for the Railbelt, Vol. P, by S. Goldsmith and E. Porter, ISER, University of Alaska-Anchorage, Sept. 1982 report, Battelle Pacific Northwest Laboratories.

price of electricity from natural gas generation at the time the project would begin operation).

Changing revenue outlook. Worldwide crude oil prices had escalated dramatically in the aftermath of the Iranian crisis of 1979. In February 1981, the contract price for Alaska North Slope crude on the Gulf Coast had peaked at $36.90 per barrel, with experts predicting that prices would steadily increase into the distant future. Long-term revenue forecasts prepared in mid-1981, consequently, indicated that the State of Alaska would be phenomenally wealthy. The Acres American feasibility study referenced the long-term revenue forecast published by Battelle Pacific Northwest Laboratories as part of a major study of alternatives to the Susitna project. Table 2 and Figure 3 show this revenue forecast. Clearly, cash financing of Susitna was a plausible option in 1981.

In mid-1982, however, a dramatic decline occurred in the long-term revenue forecast, as indicated in Table 2 and Figure 3. Full cash financing for the Susitna project was no longer an obvious possibility, but some form of state subsidy remained clearly plausible.

Because of the revised revenue outlook between 1981 and 1982, some disquieting commentary on the viability of the project began to appear. A report by Tussing and Erickson in September 1982, for example, argued that the oil prices of 1980 and 1981 were artificially high and could not continue to be tolerated in the marketplace; that lower oil prices nullified most of the economic assumptions used to justify the Susitna project; and that, by implication, the state would not be able to provide the cash grants necessary to finance the project.[3]

1983

In 1983 an application for a federal license for the Susitna project was filed; it proposed two financing options. In spite of this, however, the APA initiated new financial and economic analyses for the project because of continuing declines in oil prices.

FERC application. On 28 February 1983, an application was filed with FERC for a federal license to construct and operate the Susitna project. With regard to finan-

Table 2. State of Alaska General Fund Revenue Forecasts, 1981 to 1986.
(In $ millions, nominal.)

	1981	1982				1983			
YEAR		MARCH	JUNE	SEPT.	DEC.	MARCH	JUNE	SEPT.	DEC.
1985	8081	3487	3575	3567	2206	2981	3450	3514	3435
1986	9278	3979	4239	4261	3523	3198	3564	3892	3699
1987	10849	4569	4997	4817	3769	3385	3800	4240	4172
1988	12179	4709	5147	4901	4181	3540	3753	4106	4280
1989	13981	5242	5732	5379	4384	3554	3836	4442	4868
1990	15074	5141	5348	5096	4324	3658	4108	4606	5100
1991	16688	4717	4992	4549	4063	3374	3994	4290	4911
1992	17932	4696	4866	4441	3988	3298	3983	4157	4863
1993	19395	4611	4679	4235	3971	3250	4103	4103	4996
1994	20326	4577	4652	4163	3990	3232	4173	4077	5038
1995	20666	4268	4391	3892	3804	3092	3977	3827	4832
1996	20818	4033	4020	3608	3644	2930	3854	3613	4713
1997	20787	4246	4236	3786	3819	3008	4039	3741	4965
1998	20520	429[illegible]	4276	3837	3889	3023	4129	3737	5110

	1984				1985				1986
YEAR	MARCH	JUNE	SEPT.	DEC.	MARCH	JUNE	SEPT.	DEC.	MARCH
1985	3521	3340	3458	3343	3277	3253	[illegible]	3290	3260
1986	3702	3475	3584	3402	3037	2968	2951	3215	2721
1987	4042	3921	3958	3446	3001	2777	2209	2725	2077
1988	4194	3857	4065	3241	2764	2470	2243	2474	1614
1989	4649	4148	4360	3290	2694	2403	2106	2397	1454
1990	4837	4175	4425	3293	2632	2324	2048	2310	1419
1991	4466	4237	4414	3204	2542	2259	1926	2289	1312
1992	4394	4431	4541	3212	2515	2308	1950	2277	1232
1993	4521	4579	4639	3263	2647	2337	1958	2327	1135
1994	4535	4972	4490	3162	2551	2238	1862	2321	1096
1995	4510	4535	4479	3118	2443	2160	1824	2348	1045
1996	4516	4401	4463	3077	2313	2063	1753	2285	977
1997	4527	4248	4353	2999	2282	2040	1750	2307	1083
1998	4526	4125	4327	2931	2237	1998	1750	2307	1081

Note: The 1981 forecast was prepared by the Institute of Social and Economic Research, University of Alaska for Battelle Northwest Laboratories, derived from forecasts of petroleum severance tax and royalty income by the Alaska Department of Revenue, June 1981. The 1982-1984 forecasts were prepared by Alaska Office of Management and Budget, derived from forecasts of petroleum severance tax and royalty income made by the Alaska Department of Revenue. These forecasts represent the 50th percentile probability estimates (there is an equal chance that the actual value will be more or less than the forecasted value).

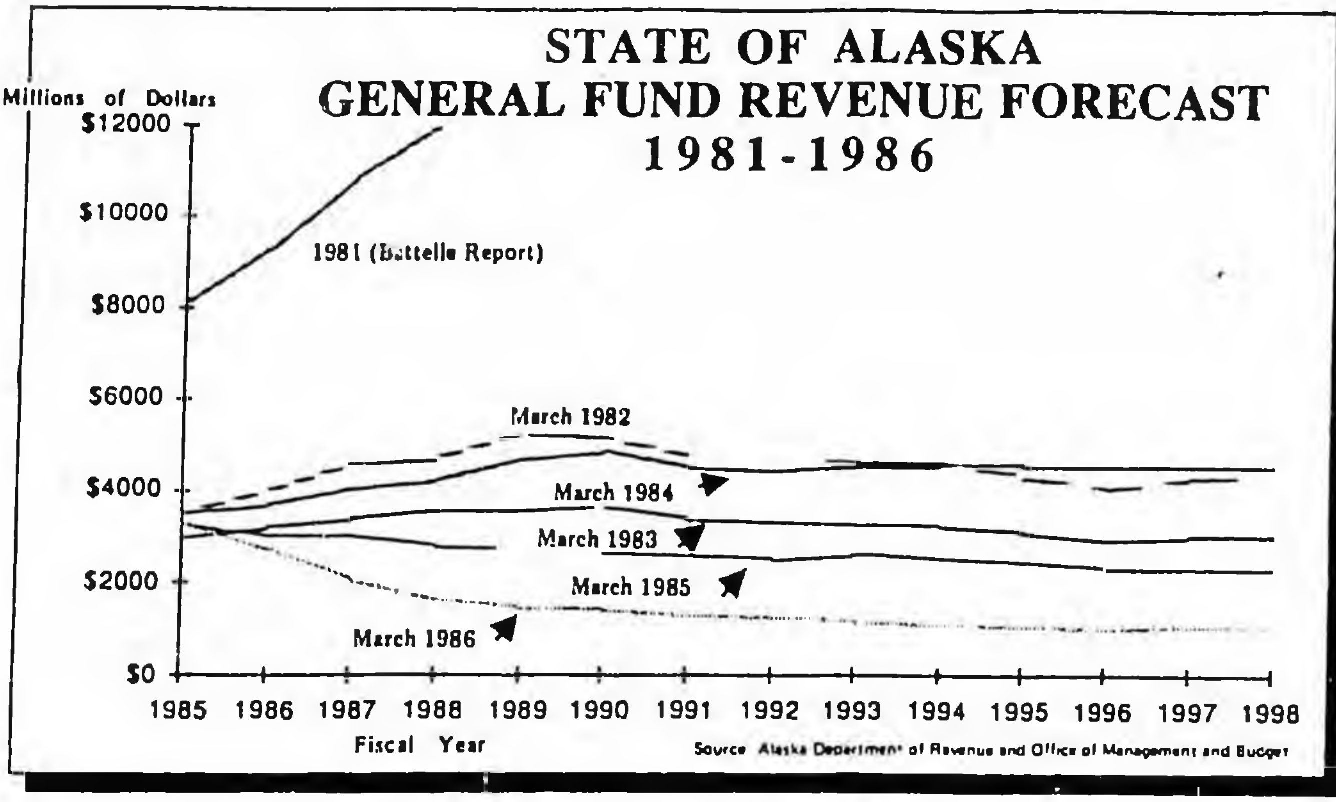

Figure 3. State of Alaska General Fund revenue forecast, 1981-1986.

cing, the license application stated that "costs for Watana through 1989 would be financed by $1.8 billion (1982 dollars) of state appropriations. Thereafter completion of Watana is expected to be accomplished by issuance of approximately $2.4 billion (1982 dollars) of revenue bonds." It also stated that the Devil Canyon phase would be financed entirely by revenue bonds. No doubt in response to revised revenue forecasts, the APA had dropped the full cash financing option, and recalculated the minimum state cash contribution to be $1.8 billion, or $500 million less than the minimum contribution of $2.3 billion identified earlier in the Acres American report.

Concern about the future price of crude oil—the keystone of the project's economic and financial feasibility assessments—was thereupon expressed by FERC's staff. Noting several deficiencies in the state's application, FERC called for the APA to incorporate updated oil price forecasts in its economic and financial feasibility studies. In response to this and to other critiques of the existing analysis, as well as to the changing oil price outlook generally, the APA contracted with the firm Sherman H. Clark and Associates (SHCA) to provide updated forecasts. In the meantime, a joint venture of two major engineering and construction firms, Harza Engineering and Ebasco Services (Harza-Ebasco), had been hired by the APA to provide engineering, design, and technical assistance in the FERC licensing process. Harza-Ebasco now initiated a review of the economic and financial studies for Susitna.

1984

During 1984 the financial dimension of the Susitna project began to receive serious attention from the APA, the legislature, and others. At mid-year, the long-term revenue outlook was robust enough to support an optimistic view that the project could be financed with the help of sizeable state grants. By the end of the year, however, it had become apparent to APA financial planners that a new approach was needed.

1984 Up-date. In February 1984 the APA released the draft report *Susitna Hydroelectric Project Economic and Financial Up-date*. Much of this report was the work of Harza-Ebasco; it incorporated the oil price forecasts of Sherman H. Clark and Associates. The report validated the economic feasibility of the project, but contained a lengthy discussion of the major unresolved financing issues facing the project. This report also introduced the subsidy mechanism of "rate stabilization."

Several financing options were reviewed by the authors of the report, but two were advanced as the most feasible: (1) state appropriations of $1.5 billion for equity in the project, and $400 million for rate stabilization, with the remaining costs financed by revenue bonds; or, (2) state appropriations of $1.7 billion for equity and $350 million for rate stabilization, plus a $1.5 billion loan guaranteed by the U.S. Rural Electrification Administration (REA), with the remaining costs financed by tax-exempt revenue bonds (all figures in 1984 dollars).

Thus, under these financing proposals, the state would not only pay a substantial portion of the project's construction costs, but would also create and finance a rate stabilization fund. This fund (as explained under "Approaches to State Subsidization") would then be used to offset enough debt service on the outstanding bonds to keep the project's wholesale cost of power equal to the cost of the best thermal alternative until such time as the cost of alternative power for the project surpassed the cost of hydropower (i.e., until the "crossover point" was reached).

What characterizes the 1984 APA *Update* is its somber assessment of the many conditions that would have to be met, and the public policy decisions and commitments that would have to be made, to finance the Susitna project successfully using multi-billion-dollar debt issues. Among these were the necessity for: (1) recognizing Susitna as one of the state's highest capital funding priorities; (2) providing adequate security for the very high volume of debt, which might require a constitutionally dedicated stream of revenue from the state's petroleum resources; (3) obtaining tax-exempt status for Susitna bonds; and (4) immediately providing for sizeable state appropriations to the Susitna fund, as well as for the retention in the fund (by annual appropriation, if necessary) of the interest earned on that money.

Kentco report. Also early in 1984, a report on the Susitna project was issued by the consulting firm of William Kent and Company (Kentco), which was working under a contract with the Anchorage Chamber of Commerce. This report, too, recommended a combination of state equity, a rate stabilization fund, and residual revenue bond financing. The proposal, however, called for a larger rate stabilization fund ($778 million) and less equity ($800 million) than the 1984 *Update.* (These amounts are 1983 dollars.) The report further called for a majority of the debt to be guaranteed by REA, with the remainder to be tax-exempt municipal debt.

The Kentco report was optimistic in its treatment of the financing issue.[4] Addressing the Anchorage Chamber of Commerce, consultant William Kent stressed that his finance plan "allowed a minimum need for state investment, spread the need for state appropriation over a larger number of years, and did not present a tax exemption problem." The plan, he said, "suggests a need to start appropriating from 178 to 226 million dollars annually starting with this legislative session."

Legislative action. During the 1984 legislative session (January to June), two measures were enacted that dealt with Susitna financing: (1) the legislature approved the Watana project at a cost of $3.75 billion in 1983 dollars; and (2) the legislature made a continuing appropriation for "equity investment in and rate stabilization for the Susitna project" in the amounts of $100 million for fiscal year 1985 and $200 million for each of the six succeeding fiscal years.[5]

While the Watana construction cost figure of $3.75 billion was traceable to the Harza-Ebasco *Up-date*, the origin of the $1.3 billion (nominal dollars) total set aside by the continuing appropriation was a mystery. Many people assumed that it was based on the Kentco report and William Kent's Chamber of Commerce speech. In any case, it bore no resemblance to the finance plans proposed in the *Up-date* or those being discussed by the APA staff and board.

Meanwhile, APA staff continued to maintain that some $2 billion (constant dollars) was needed from the state to help finance the project. Thus, instead of the $200 million per year for FY1986-1991 appropriated by the legislature, $578 million per year would be required—or at least $316 million per year if interest could accumulate in the Susitna fund.[6]

Revenue outlook. Was it reasonable to expect that $316 million a year (plus interest earnings of the fund) would be forthcoming from the legislature for six successive years to finance Susitna? In mid-1984, a plausible argument indeed could be made that the money was available, *if* the legislature had the will to see the project through. Note that the revenue projections shown in Table 2 and Figure 3 for 1984 are significantly higher than those made the previous year. If one were to project that the state's operating budget would grow at the rate of inflation (approximately 5 percent) from a base of approximately $2.2 billion in FY1984, then the 1984 revenue forecasts suggest that the State would have over $1 billion a year during FY 1986-1991 to allocate for the capital projects and loan programs. Under these fiscal circumstances, appropriations of $316 million per year to a fund retaining its own investment earnings certainly was not, on the face of it at least, impossible.

By the end of 1984, however, revenue forecasts had fallen to their 1983 levels.[7] Also, additional oil price reductions seemed probable, due to a steady erosion of OPEC's influence over oil prices.

There were other reasons, as well, to believe that the expectation of massive and continuing state appropriations for Susitna was unrealistic. Notably, the 1984 Legislature had appropriated only $100 million for Susitna for FY 1985, while total capital appropriations that session exceeded $1.2 billion, comprising the largest unrestricted general fund capital budget in the state's history. This was hardly a good indication of legislative will to sacrifice other capital projects in order to pay for Susitna.

1985

During 1985 the APA and its consultants redesigned the Susitna project in an effort to facilitate its financing. Toward the end of the year a team of financial experts initiated work on a definitive plan of finance based on the reconfigured project.

Staging Proposal

At its meeting of January 23, 1985, the board of directors of the APA adopted a staff recommendation for a Susitna plan of finance that called for state appropriations of $1.94 billion over the fiscal years 1985-1995 to a fund that would retain its interest earnings. This money would be used for both equity and rate stabilization. Minutes of the meeting show that the board considered this option the best presented to date, and directed the staff to continue refining it.

By this time, however, it was increasingly apparent to many people that if the project were to go forward, it would have to do so under a financing scheme that did not require such large state cash contributions. Among those recognizing this were high-level individuals in the parent companies of the Harza-Ebasco joint venture, who in January 1985 held informal meetings with the Governor, APA executive staff, and board members to discuss a proposal for staging the construction of the Watana dam. Under this approach, Watana would be constructed in two phases (the first and the third phase); the Devil Canyon dam would be the second, middle phase of the project. The virtue of developing the project in three phases instead of two was primarily financial. Three phases of construction would match more closely than two phases the growth of electricity demand in the Railbelt. As a consequence, there would be less unused capacity in the Watana dam in the early years of project operation, and therefore a greater ability of utility customers to carry the burden of revenue bond financing. Thus, according to the staging proposal, all three phases would be financed entirely by revenue bonds, with a comparatively modest state cash contribution remaining necessary for rate stabilization only in the early years.

In February the Board received a public presentation of the conceptual proposal and authorized Harza-Ebasco to develop it further in an expeditious manner. At its meeting of May 3, 1985, the Board approved the staged approach, and directed the APA staff to begin preparing an amendment to the FERC license application that incorporated the reconfigured project.

By October, APA staff and consultants had prepared a comprehensive analysis of the economic and financial aspects of the new three-phase project. On the basis of assumptions about the cost of generating power from natural gas and coal (the next best alternatives to Susitna), the APA staff calculated that a rate stabilization fund adequate to keep the wholesale cost of Susitna power equal to its thermal competitor would require as little as $253 million (1985 dollars). During the 1985 legislative session the continuing appropriation to Susitna of $200 million had been made, so there was already enough money in the bank to finance the project under this scheme (provided the interest on this money was allowed to accumulate in, or was annually appropriated to, the fund).

When the APA released its draft License Application Amendment in November, the estimate of state contributions to a rate stabilization fund had decreased further to $220 million (1985 dollars). The primary reason for these low estimates of rate stabilization was the assumption that without Susitna large-scale coal plants would be required in the 1990s to meet Railbelt energy demand, causing substantial rate increases.

Preparation of a financial plan. By late 1985 it was increasingly evident that the question of financing was critical for the Susitna project. In particular, financial advisers to the APA were concerned about the real-world problems of selling so much debt for a single project in the national market. These were the same individuals who had contributed the lengthy discussion of these problems to the 1984 *Update*. The task of marketing Susitna bonds was much more problematic now that the state equity contribution had been eliminated altogether.

Pressure also was coming from the legislature for the APA to produce a credible plan of finance for Susitna. Finally, critics of the project, such as representatives of public interest advocacy groups and the environmental lobby, were openly asserting that the project was not financially viable. They claimed that the bond market would not absorb so much debt for a single massive project intended for a comparatively small market area that was isolated from the power grid of the continental United States.

Late in 1985, APA's executive director assembled a team of financial advisers (including several bond underwriters, bond lawyers, and others) to begin preparing a definitive plan of finance for the project.

1986

The team of financial advisers charged with preparing a workable financing plan for the Susitna project presented a draft plan of finance to the board of directors on January 23, 1986. The revelations contained in this document led directly to the termination of the project two months later.

> *". . . the finance team concluded that only a commitment of the earnings of the Alaska Permanent Fund would suffice to secure the state's special revenue bonds."*

Plan of finance. The draft finance plan presented to the Board in January was built on the premise that very little state cash would be available, and that all project costs would therefore have to be covered through the sale of revenue bonds. Summed over time, these bonds would total more than $20 billion (nominal). The key question was whether the utilities and the state could successfully carry that much debt.

To assess the debt capacity of the utilities, the finance team calculated the maximum annual revenue that the utilities could generate for debt service, using as a basis the assumption that the utilities' customers could tolerate a maximum rate increase of 3 percent (real) per year. Then, using a 25 percent estimate for the maximum tolerable one-time rate hike that the Railbelt ratepayers could withstand in the event the project never operated, the finance team estimated the maximum security that the Railbelt utilities could offer bondholders against the risk of the project's never being completed.

The results of this analysis indicated that the upper limit of indebtedness for the utilities for the project was $2 billion (nominal). Thus, the State of Alaska would have to issue special revenue bonds to cover the remaining project costs. The State of Alaska, however, could not adequately secure that amount of bonds, even with the pledge of its general obligation debt capacity. After reviewing all plausible alternative sources of security, consequently, the finance team concluded that only a commitment of the earnings of the Alaska Permanent Fund would suffice to secure the state's special revenue bonds.

The financial team also concluded that, beyond issuing special revenue bonds and pledging the income from the Permanent Fund as security, the State of Alaska would also have to provide a rate stabilization fund of $520 million (1985 dollars; or $2.3 billion in nominal dollars) and an additional $323 million (1985 dollars) preconstruction licensing and development costs. The reason the rate stabilization requirement was higher than the APA estimate published in the draft FERC license amendment ($220 million, 1985 dollars) is that the draft finance plan stabilized rates to the level of a 3 percent (real) annual increase in retail electric rates, rather than to the somewhat higher level of electric rates estimated by the APA to result from the best thermal alternative.

At its meeting of January 23, the APA board requested its executive director to submit the draft Susitna plan of finance to rigorous scrutiny by a major municipal bond underwriting firm, to test the validity of the finance team's findings. Under contract to APA, the firm of Prudential-Bache Securities then reviewed the analysis and conclusions of the plan, and concurred with them in a report dated March 21, 1986. Three days later, at its meeting of March 24, the APA board voted to withdraw the Susitna license application.

REFLECTIONS ON THE QUEST FOR FINANCE: PROBLEMS WITH RATE STABILIZATION

Even if a politically acceptable means of securing the state's Susitna revenue bonds had been found, it is doubtful that negotiations between the APA and the Railbelt utilities would have been consum-

'mated under the finance plan advocated by the APA—that is, with rate stabilization providing the only vehicle of state subsidy.

At the time the Susitna project collapsed, negotiations between the Railbelt utilities and the APA for conditional power sales contracts had been under way for some time, but they were still in very preliminary stages. The underlying problems of developing a contract that incorporated a rate stabilization fund were therefore never fully identified nor confronted by the negotiators.

Neither of the existing contracts between APA and purchasers of power from its projects (the four-dam pool and Bradley Lake) incorporate rate stabilization. Therefore the following analysis of the rate stabilization approach is speculative insofar as the concept has yet to be implemented. Nonetheless, in the course of financial planning for the Susitna project, several seriously complicating features of rate stabilization emerged.

Problems with Rate Stabilization

There are two reasons for doubting that power sales contracts placing significant reliance on a rate stabilization fund could have been successfully negotiated between the APA and Railbelt utilities. The first has to do with the pervasive public opinion in the Railbelt region that the Susitna project was going to bring immediate rate relief, or at least stabilize electric energy prices at their then-current level. The second is that probably neither the utilities nor the state would have been willing to expose themselves to the risks that rate stabilization entails.

Public expectations. Financing for APA's other major hydroelectric projects, the four projects of the so-called "four-dam pool" and Bradley Lake, relies on state subsidy in the form of equity. In both cases, state cash appropriations to the projects cover approximately half of the cost of construction, with the remainder of project costs covered by borrowing.[8] This financing assures customers of a wholesale cost of power that is comparable at the outset to the cost of power from thermal plants.

Railbelt residents had come to expect the same of the Susitna project. The project, after all, had long been touted as the most economical source of Railbelt power available, and the best defense against sudden and dramatic rate increases likely to be caused by the expiration of existing favorable contracts which made Cook Inlet natural gas some of the cheapest fuel in the country.

By the time rate stabilization entered the financial picture in 1984, however, Susitna could promise favorable rates to consumers only in the long run. With rate stabilization, utility customers would have to pay along the price curve of the thermal alternative until a point somewhere in the distant future (10 or more years after the project was operating). That price curve, consequently, would expose utility customers to the very same near-term rate shocks from rising fuel costs that Susitna was presumed to avoid.

As this realization permeated the utilities' governing boards, the municipal governments, and the public generally, it is reasonable to expect that negotiations over Susitna power sales agreements would have become very protracted and complicated indeed.

> *"Thus, a definite risk existed that the Railbelt utilities might have to pay a substantial premium for Susitna power. Further, the potential magnitude of this premium was very great . . . ."*

Allocation of risk. Among the risks associated with any major energy project, two are crucial: (1) the risk that the project will cost substantially more to build than assumed in feasibility studies; and (2) the risk that the price of competing energy sources will not perform as expected (i.e., will fail to increase, or not increase as rapidly as thought).[9] Either eventuality will leave the project an overpriced producer in the market, at least in the near term. Somehow, then, these risks must be borne by the developer of an energy project or the purchasers of the power, or allocated between them.

In the case of Susitna, contract negotiations between the APA and Railbelt utilities never progressed to the issue of the allocation of these risks. Nevertheless, the approach to project financing adopted by the APA after 1985—i.e., subsidy to be used exclusively for rate stabilization—so accentuated the risk of falling alternative energy prices that neither the utilities nor the state would have been willing to assume it.

The risk of cost overruns on any major engineering project is always present, and has many potential sources. In the case of Susitna, the probability of significant cost overruns was not especially high when compared to major projects using new and complex technology and subject to strict governmental regulation (as in the case of nuclear power plants, for example). Nonetheless, it is unlikely that the utilities would have accepted any of this risk in power sales agreements with the APA.

A risk that was more difficult to analyze and to deal with in the Susitna case surrounds the behavior of alternative energy prices. Here is where the risk-related problems inherent in rate stabilization financing became apparent. A rate stabilization fund of a fixed amount for Susitna would guarantee a floor on wholesale electricity prices, based on a projection of prices from the thermal alternative. If alternative energy prices were to fall below this projected floor, access to them would be blocked by a Susitna power sales agreement. Thus, a definite risk existed that the Railbelt utilities might have to pay a substantial premium for Susitna power. Further, the potential magnitude of this premium was very great, as revealed in an analysis prepared by the APA in October 1985.

The APA's 1985 risk analysis for Susitna investigated the sensitivity of the requirement for rate stabilization to certain fossil fuel price assumptions.[10] It showed, in particular, that the present value of the cost of a rate stabilization fund was only $253 million using a "base case" set of assumptions about (a) long-term crude oil price trends, (b) the future availability of Cook Inlet natural gas for electrical generation, and (c) the method by which Cook Inlet gas prices would be set in the future. When those "base case" assumptions were relaxed, however, the present value of the cost of the rate stabilization fund soared. Under conservative but very reasonable assumptions, for example, the analysis showed that a fund of between $1 billion and $2 billion in 1985 dollars would be necessary to stabilize Susitna's rates at the level of the thermal alternative (natural gas). The difference between the "base case" estimate of $253 million and this estimate, consequently, represented

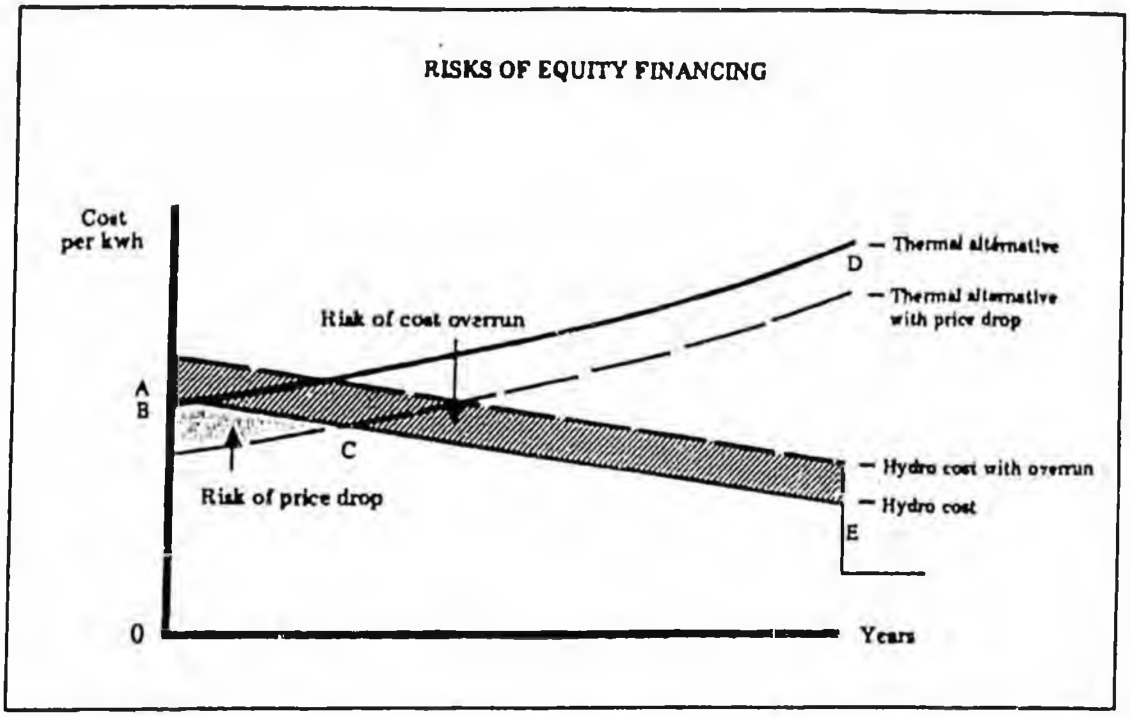

Figure 4. Risk of cost overrun is the same under either form of subsidy, but the risk of fossil fuel prices being lower than expected is less with equity than with rate stabilization, Figure 5.

the magnitude of the total rate premium that Susitna customers might have to pay if those conservative but reasonable assumptions proved true.

Exposure to the risk of declining alternative (fossil) fuel prices is significantly less under the equity financing approach than the rate stabilization approach. This is because the gap between the cost of power from the hydro project and the cost of power from the thermal alternative will close sooner under equity financing. The differences between rate stabilization and equity in this respect are best explained graphically. Figures 4 and 5 illustrate that the risk of cost overruns are identical under both financing approaches, but that the risk of declining fossil fuel prices is greater under rate stabilization. The crossover point C in Figure 4 occurs much sooner than the crossover point C in Figure 5, thereby reducing the length of time consumers would have to pay a premium for hydropower in the early years, if an unexpected decline in fossil fuels should occur.

From the consumers' perspective, a sizeable equity contribution is the preferred method of providing state subsidy to an energy project such as Susitna, because it minimizes risk and offers the prospect of rates lower than those that would otherwise prevail. From the state's perspective, on the other hand, rate stabilization is the preferred approach because it minimizes the state subsidy. The experience of the APA with the Susitna project suggests that to the extent it is relied upon exclusively, rate stabilization may simply not be viable, particularly when used for a sizeable project and particularly in a period of unstable fossil fuel prices. When state subsidy in the form of cash grants is made to a project, the money should be used to reduce the overall level of debt for the project, rather than reduce the debt service burden in the early years of operation with the aim of keeping wholesale electricity costs comparable to a long-term projection of the avoided costs from alternative generation sources.

SUMMARY

In the course of planning for the Susitna project, three sources of financing were proposed: (1) state appropriations to cover some portion of construction costs (equity); (2) state appropriations to cover some portion of the debt service on revenue bonds during the early years of project operation (rate stabilization); and (3) revenue bonds.

Planning for the Susitna project began with the assumption that cash appropriations from the state's general fund would cover all project costs—i.e., a 100 percent equity approach. Later, it was proposed that a mix of state equity and revenue bonds be used to finance the project. Following that, the concept of a rate stabilization fund was added to the combination of equity and revenue bonds (because rate stabilization tended to reduce the amount of required state equity). Finally, the equity component was eliminated altogether, and it was decided that financing for the Susitna project would be accomplished entirely by revenue bonds and a rate stabilization fund.

This evolution of Susitna's financial planning was driven by the eroding outlook for state revenues and by uncertain evidence of legislative resolve regarding financial commitment to the project. From the beginning, it was recognized that Susitna would require a substantial subsidy from the state. Ultimately, an acceptable plan of finance for the project eluded the APA because the state did not have enough money to provide the subsidy the project needed. The end came because of the problem of providing adequate security for the large volume of revenue bonds called for by the finance plan, and this problem stemmed from the state's inability to provide equity investment in the project sufficient to reduce borrowing requirements to levels that could be secured by the utilities through conventional power sales contracts.

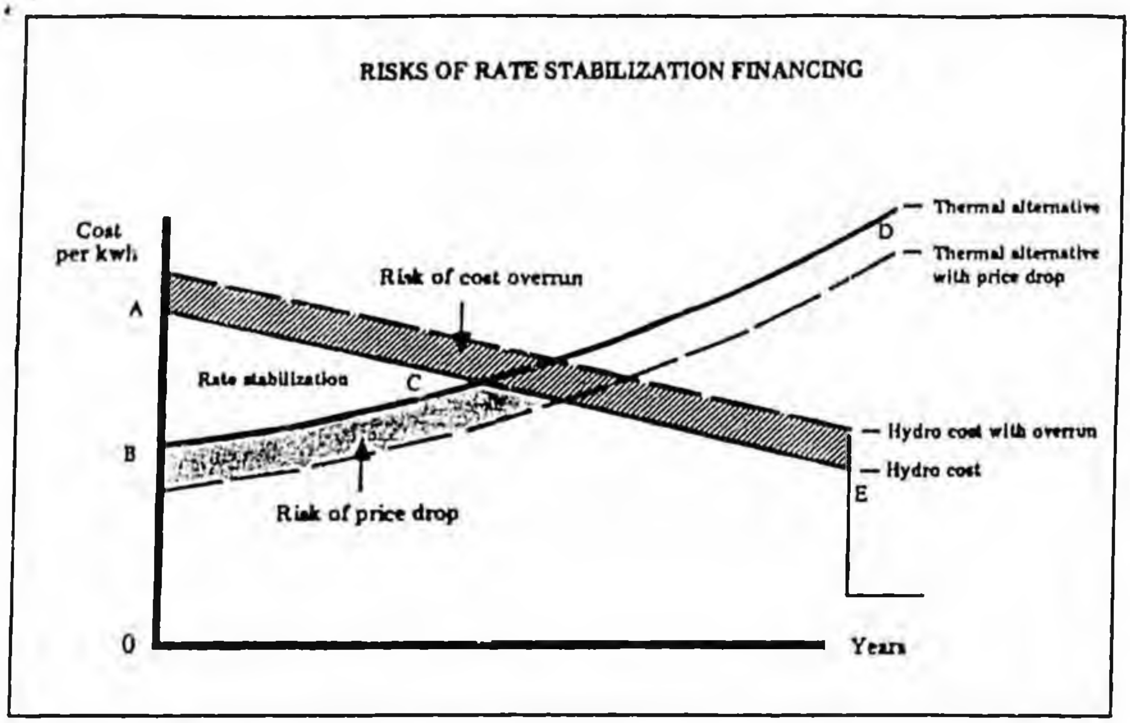

Figure 5. Risk of fossil fuel prices being lower than expected is greater under the rate stabilization subsidy approach because it takes longer to reach the crossover point than with the equity approach, Figure 4.

Even if a politically acceptable means had been devised to secure the Susitna project revenue bonds, it is unlikely that a workable contract could have been successfully negotiated between the Railbelt utilities and the APA that relied heavily on a rate stabilization fund of a fixed amount. There are two reasons for this evaluation of the situation: (1) utility customers in the Railbelt expected the Susitna project to protect them from retail electricity rate hikes, when in fact the rate stabilization approach assured them of rate hikes and would not result in savings to customers for many years, and (2) the concept of rate stabilization entailed risks that neither the state nor the utilities would be willing to assume. From the point of view of public policy considerations, rate stabilization might be the preferred approach to providing state subsidy to large energy projects because it minimizes state contribution. However, the experience of the Susitna project suggests that it is not practical. State subsidy for future hydroelectric projects (to the extent it is necessary and available) should take the form of equity, i.e., it should reduce the need for borrowing.

NOTES

[1] State subsidy was regarded by many people as desirable from a public policy perspective, because it provides a means of distributing the state's oil wealth to citizens. Other aspects of the issue of subsidy for the project are discussed in Gordon S. Harrison, "Science, Susitna and political decision making." *The Northern Engineer*, 1984, Vol. 16, No. 3.

[2] In the real world, a project would never be without debt, because major renewals and replacements of the turbine, generator, and switchyard equipment would have to be financed through the issue of new debt.

[3] Arlon R. Tussing and Gregg K. Erickson, "Alaska Energy Planning Studies," Policy Analysis Paper No. 82-13, a review of three consultant studies submitted to Alaska state agencies in fiscal year 1982, November 18, 1982. See also, Richard Emerman, "The Probable Effect of Lower State Revenue Forecasts on the Projection of Electricity Demand in the Railbelt," policy and analysis paper 82-10, Division of Policy and Development and Planning, Office of the Governor, September 21, 1982. See testimony of Gregg Erickson on SB 25, SB 26, and SB 244 before House Finance Committee on May 18, 1981 (minutes, p. 1325).

[4] The Kentco plan of finance was not realistic, however, because of cutbacks in federal funds for REA. In any case, the Susitna project would not have received favorable consideration by that agency because most of the power from the project would be sold to "urban cooperatives," which are accorded a low priority in the distribution of REA funds. See "Transcript of Questions and Answer Session" following address by U.S. Senator Ted Stevens to the Thirteenth Alaska State Legislature, February 1984.

[5] The continuing appropriation was declared unconstitutional on August 30, 1985, by the Alaska Superior Court.

[6] See minutes of APA board meeting of November 9, 1984.

[7] It should be noted that the 30th percentile, risk-adjusted forecasts developed by the Department of Revenue were even lower, significantly, than the mean probability forecast shown in Table 2. The 30th percentile forecast reflects a 70 percent probability that the estimate will be exceeded, and is used by the executive and legislative branches for budgeting purposes.

[8] In the case of the four-dam pool, the debt component is a state-funded long-term subsidized loan. In the case of Bradley Lake, which has just begun construction, the debt component will be project revenue bonds issued by the APA and secured by contracts with the utilities purchasing power from the project.

[9] A third major risk is that the forecast demand for the output of the project will not materialize. This was a major risk of the Susitna project, but one that was not taken seriously by Railbelt utility managers, who constantly chided the APA for its conservative estimates of load growth. Thus, it seems unlikely that allocation of this risk would have impeded contract negotiations with APA.

[10] The results of the analysis, in table format, were included in a package of material prepared by APA staff and consultants and distributed to the Board of Directors at the meeting of October 2, 1985. The table is titled "Sensitivity Analysis," but has neither table number nor page number. Further, the table is not reproduced in the APA's draft FERC license amendment, although the general outcome of the sensitivity analysis is alluded to in Exhibit D, p. D-4-5, of the draft amendment. ♦

HFIN Steven Haagensom, Energy Coordinator, AEA

3/5/08

- Sizing is critical for a hydroelectric project. Not only for the megawatt capacity but also identifying the available water resources to ensure a year around power source.

- The Hydroelectric workgroup looked at the Susitna at a very high level, using what were believed to be realistic estimates for capital costs and operating costs.

- SB[redacted] would take the next step to determine the proper size for the Railbelt energy system, both now and in the future.

- The hydro workgroup initially sized Susitna at 600 megawatts to serve the entire Railbelt from Fairbanks to Homer. Using this capacity, I did a cost comparison of a 600 MW Susitna project to 600 MW's of new high-efficiency combustion turbines.

- This back of the napkin analysis shows the yearly costs of debt service, O&M and fuel for Susitna to be $259 million or about 5cent/kWh, and the equivalent cost of the Combustion Turbines at $501 million. This is a savings of about $250 million per year, that we should seriously look at.

- Susitna will emit no CO_2, where the turbines will emit 2.5 million tons of CO_2/yr. Susitna will also reduce Anchorage gas consumption by 25 billion cubic feet of gas per year.

  ~~($6.0/mcf for Anchorage, below Henry Hub pricing of $8.39/mcf on 2/12/08)~~

- The assumptions used were realistic and reasonable, but need to be projected into the future and verified, so that a decision about Susitna can be made on an informed basis.

- SB ~~#246~~ provides that detailed analysis of the Susitna Hydroelectric Project. I urge your support of this bill.

- If Susitna is constructed as a result of this bill, it will benefit the economy and the people of the State of Alaska for generations to come.

- Thank you again for this opportunity to testify[redacted].
  I would be happy to answer any questions.

HYDRO- Storage	600 000 kW	Capex	$3 000 000 000		17,938 728	mmBTU/yr	100%		I&D	$217,379,549	$ 12.12
	20.0	Debt	50	years					O&M	$ 42,048,000	$ 2.34
		Interest	7.0%						Total	$259 427 649	$ 14.46

600 MW Susitna | HYDRO- Storage | $ 0.0494 /kWh

CCCT- Natural Gas	400 000 kW	Capex	$ 640 000 000			Efficiency	48%		Fuel	$149,489,400	$ 12.50
		Debt	30	years	11 959 152	mmBTU/yr			I&D	$ 51,575,298	$ 4.31
		Interest	7.0%		2 899 845 211	# CO2/yr	$6.00	/mcf	O&M	$ 9,600,000	$ 0.80
									Total	$210 664 698	$ 17.62

400 MW CCCT Anch | CCCT | $ 0.0601 /kWh

CCCT- Petroleum	200 000 kW	Capex	$ 320 000 000			Efficiency	48%		Fuel	$260,304,925	$ 43.53
		Debt	30	years	5 979 576	mmBTU/yr			I&D	$ 25,787,649	$ 4.31
		Interest	7.0%		1 988 956 467	# CO2 /yr	$ 20.90	/mmBTU	O&M	$ 4 800,000	$ 0.80
									Total	$290 892 574	$ 48.65

200 MW CCCT Fa | CCCT | $ 0.1660 /kWh

Total	$501 557 273	$ 27.96

$ 0.0934 /kWh

Total	4 888 801 678	# CO2/yr
	2 444 [illegible]	tons CO2/yr
	73 332 025	tons CO2/30 years

The Alaska Center for Energy and Power

3/5/06

Energy Research at the University of Alaska

Contact: Gwen Holdmann, Organizational Director, Alaska Center for Energy & Power
gwen.holdmann@uaf.edu, 907-474-5402 (O), 907-590-4577 (cell)

The Alaska Center for Energy and Power (ACEP) seeks to meet state, industry, and federal demand for applied energy research. New energy research and testing is needed for the short and long term to lower the cost of energy in rural Alaska and develop economic opportunities for the State, its residents, and its industries. The three legs of ACEP include:

- **Rural Energy Solutions:** Provide applied research and testing that will lead to lower power cost in rural Alaska. ACEP will be where the rubber meets the road for rural energy technologies. We seek to be a proving ground so that efficient and effective technologies are implemented in rural Alaska where diesel fuel and power failure come at a high cost.
- **Big Power.** We will provide the research needed to develop big power in Alaska to service resource development needs in both the state and the Arctic. A gold rush has begun for resources in a new Arctic that has diminished sea ice. Growth in Alaska and the Arctic will require power and the state should position itself to be the new power broker. Iceland, which currently can sell green power at $0.02/kWh is attracting today's industry. With research, initiative, and implementation, Alaska can harvest the benefits of the untapped resources in this new Arctic.
- **The Oilfield of the Future:** ACEP will provide the research needed to develop the "Oilfield of the Future". We will extend our ongoing research in gas hydrates, heavy oil, carbon sequestration and renewables so that the oil industry and the state are prepared for the future.

Alaska's world class energy resources, including oil, gas, and coal are the source of much of the state's wealth. In Alaska, we have unique challenges and opportunities associated with large undeveloped areas, particularly related to economically competitive power for rural villages and remote industrial sites. At the same time that we are meeting energy needs of Alaska's citizens and businesses, Alaska has major emerging opportunities, such as geothermal development in the Aleutian Islands. Alaska has resources, the potential for cheap power, and resides at a global crossroads. A large power plant in the Aleutians does not need to be connected to a grid. The Aleutians could serve as a power center for a new generation of power-placed industry in Alaska, just as has been experienced in Iceland.

ACEP will be interdisciplinary, needs driven, and agile. We are developing a wide range of partnerships. For example, we have local partnerships built around sustainability that include the Fairbanks Economic Development Corporation, the Cold Climate Housing Research Center, the Fairbanks North Star Borough, and Chena Hot Springs Resort. We are also building partnerships statewide (e.g., Alaska Energy Authority) and nationwide (e.g., DOE National Laboratories). ACEP will include all three MAUs of the University, taking advantage of existing strengths at UAS, UAA (e.g., the Institute for Social and Economic Research etc.), and UAF (e.g., the Geophysical Institute, International Arctic Research Center, Agriculture and Forestry Experiment Station etc.).

ACEP will also seek to increase educational opportunities in energy for students throughout Alaska by offering seminars and courses on a range of energy related topics, facilitating rural training opportunities, and offering graduate and undergraduate research fellowships.

We seek programmatic funding that will be directed to research and testing by an industry and agency panel. At present, we are seeking investment from state, federal, and industry sources. We believe that this investment will give our rural communities access to less expensive power and more thoroughly tested technologies, our industry access to research on future development opportunities, such as methane hydrates, and the state the opportunity to diversify through development of power as a resource, drawing industry to Alaska.

UAF
UNIVERSITY OF ALASKA
FAIRBANKS

FAIRBANKS
Economic Development
CORPORATION
301 Cushman St., Suite 301, Fairbanks, AK 99701

3/5/08

February 11, 2008

Representative Craig Johnson
Alaska State Legislature
State Capitol
Juneau, Alaska 99801

Attn: Jeanne Ostnes

Subject: Susitna Dam

Alaska is facing a growing and unanswered energy crisis. Within the next 10 years Alaska's Railbelt communities well need to replace 100% of their current power generation. In Rural Alaska the energy crisis is threatening to close communities that have existed hundreds of years.

Finding affordable, sustainable and environmentally friendly energy solutions for Alaska is the right investment in Alaska's future. Moving beyond an economy dependent on Federal spending and the price of oil will require leadership from both the State of Alaska Legislature and our Governor. We must make investments in Alaska that will contribute to our more self-dependent economic future.

We urge the Alaska State Legislature and the Governor of the State of Alaska to support legislation that would lead to the analysis and hopefully the development of the Susitna Dam Project.

Sincerely,

Jim Dodson
President & CEO
Fairbanks Economic Development Corporation

Phone: (907) 452-2185
1-888-476-FEDC
www.investfairbanks.com
Fax (907) 451-9534

3/5/08

GVEA
Golden Valley Electric Association
PO Box 71249, Fairbanks, AK 99707-1249 • (907) 452-1151 • www.gvea.com
Your Touchstone Energy Cooperative

RESOLUTION NO. 102-08

A RESOLUTION OF THE BOARD OF DIRECTORS TO SUPPORT THE STUDY OF A SUSITNA HYDRO ELECTRIC PROJECT

WHEREAS, the Golden Valley Electric Association, Inc. ("Golden Valley") Board recognizes that renewable energy plays an important role in Alaska's energy supply; and

WHEREAS, the Railbelt relies heavily on fossil fuel, which is subject to high and volatile pricing; and

WHEREAS, the electric production from hydro electric projects emit no CO_2; and

WHEREAS, the Susitna Hydro Electric Project was studied extensively in the 1970s and substantial progress was made on the project; and

WHEREAS, the size and financing of the project need to be determined;

BE IT RESOLVED that the Board of Directors of Golden Valley hereby supports efforts to further advance the Susitna Hydro Electric Project.

CERTIFICATION

I, William D. Digan, do hereby certify that I am the Secretary of Golden Valley Electric Association, Inc., an electric non-profit cooperative membership corporation organized and existing under the laws of the State of Alaska; that the foregoing is a complete and correct copy of a resolution adopted at a regular meeting of the Board of Directors of this corporation, duly and properly called and held on the 28th day of January, 2008; that a quorum was present at the meeting; that the resolution is set forth in the minutes of the meeting and has not been rescinded or modified.

IN WITNESS WHEREOF, I have hereunto subscribed my name and affixed the seal of the corporation this 28th day of January, 2008.

(SEAL)

GOLDEN VALLEY ELECTRIC ASSN. INC. CORPORATE SEAL 1961 ALASKA

William D. Digan

William D. Digan, Secretary

3/5/08

SUSITNA RENEWABLE HYDRO POWER SYSTEM AND POTENTIAL RURAL POWER SYSTEMS

Figure 1.--Upper Susitna block, Susitna River basin.

3/15/08

Side-by-Side Comparison
Susitna and Chakachamna Hydropower Projects

Susitna	Chakachamna
$159 million spent on investigations over 10 year period – 1975 thru 1985	$300 Thousand spent over 3 year period – 1980 thru 1983
6.5 billion KWH energy output from two world class dams	1.6 billion KWH energy from one small diversion dam
$5.4 billion construction cost (1985$) Source: Susitna FERC License	$0.9 billion construction cost (1985$) Source: Susitna FERC License
Precise cost estimate	Conservative cost estimate
880 foot dam at Watana (62 million cu yd earth dam) and 664 foot dam at Devil Canyon (1 million cu yd concrete arch dam)	49 foot high rock fill dam at lake outlet and 10 mile power tunnel to underground powerhouse on McArthur river
$1.0 billion needed for new transmission lines to bring power to load centers	Only 42 miles of new transmission lines required to bring power to load centers
Reservoirs inundates 45,500 acres of land and 90 miles of existing stream channel	Existing lake – no additional land inundated
Significant native land directly impacted by project footprint	No native land directly impacted by project footprint
Project built on main stem of a major river that flows into Cook Inlet	Project diverts water from existing lake that flows into Cook Inlet
Project built on river system that is major contributor to five species of Cook Inlet salmon runs	Project built on much smaller river system that is contributor to five species of Cook Inlet salmon runs
No existing roads to the project sites	No existing roads to the project sites
Project killed by governor in 1985 when price of oil fell to $10/barrel	Project shelved by Ak Power Authority in 1983 because it competed for Susitna market
Would require major state investment and agency to develop the project – dormant	Within the capability of private sector to develop – under active investigation by TDX Power

Source: Preliminary Info from current TDX Chakachamna studies

MEA
Synergy Works.
Matanuska Electric
Association, Inc.
P.O. Box 2929
Palmer, Alaska 99645-2929
Telephone: (907) 745-3231
Fax: (907) 761-9368

3/5/08

February 13, 2008

Representative Craig Johnson
State Capitol
Juneau, AK 99801

Dear Representative Johnson:

Thank you for the opportunity to provide comments in support of **HB 336, Susitna Hydroelectric Project.**

Matanuska Electric Association (MEA) is the oldest and second largest electric utility cooperative in the state. MEA serves more than 53,000 customers in the Matanuska-Susitna Valley and Chugiak-Eagle River areas of Alaska.

On February 11, MEA's Board of Directors unanimously passed a resolution supporting this legislation. As soon as a formal, signed copy is available, I will forward it to you.

MEA supports HB 336 and your efforts to encourage the development of renewable energy projects in our service territory that would benefit the entire Railbelt. Last year, MEA expressed its desire to see the remaining balance of the Railbelt Energy Fund be dedicated to Southcentral Railbelt renewable energy projects.

Reviewing existing studies on the Susitna Hydro Project will spark important conversations about long-term energy policy for Alaska. While the actual development of a Susitna hydro project may take decades to complete, MEA is encouraged by the forward thinking laid out in HB 336.

Sincerely,

Lorali M. Carter
Manager of Government & Corporate Communications

cc: Representative Kevin Meyer, Co-Chairman, House Finance Committee

Enclosure: MEA Press Release on Railbelt Energy Fund Dedication

315|06

FINAL RELEASE

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from Matanuska Electric Association with offices in Palmer, Wasilla and Eagle River, Alaska

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PALIN VETOS RAILBELT ENERGY FUND: MEA'S RESPONSE– *"Put it all toward renewable energy projects."*

PALMER – "While MEA is disappointed the Governor has rejected the recommendations of the Legislature, MEA respects the fact that the Governor may have a different policy agenda and understands that she has every right to veto the appropriations," said MEA General Manager Wayne Carmony.

"Despite several meetings with the administration, the governor's representatives didn't really know what her views were on the Railbelt Energy Fund. It would have been helpful if the administration's position had been known. If the Governor had shared her policy views earlier, MEA would have been happy to work with her," explained Tuckerman Babcock, Assistant General Manager.

MEA General Manager Wayne Carmony announced he will be recommending that the state should dedicate the Railbelt Energy Fund - approximately $75 million - to Southcentral Railbelt renewable energy projects. An ideal vehicle for the appropriation is the Renewable Energy Fund legislation pending before the Legislature.

As for the proposed transmission lines vetoed by Governor Palin, MEA members will simply have to step up and pay the extra $26.5 million. Carmony observed, "MEA has always been willing to pay our own way, however with the state handing out subsidies to Southeast, Rural, and Fairbanks ratepayers, MEA believed Mat-Su and Eagle River ratepayers deserved a fair share of state support."

"MEA hopes she will decide to support dedicating the Railbelt Energy Fund for small to medium renewable energy projects which are otherwise so difficult for utilities to sponsor and subsidize."

Governor Palin vetoed $20 million for transmission to Fire Island for a wind farm, $12.5 million for transmission in the core area of the Mat-Su, 12.5 million for transmission on the Kenai Peninsula, $14 million for transmission in the Susitna Valley to protect MEA members from the effects of changes to the Alaska Intertie and $12.5 million to get the state-owned Healy Clean Coal project running.

The Railbelt Energy Fund has historically been the source of windfall appropriations for the customers of Golden Valley Electric in Fairbanks ($80 million in state subsidies). No other Railbelt utility has received a fair share, and only $75 million remains in the fund.

Both the 2006 and the 2007 legislatures have now tried unsuccessfully to rebalance the benefits of the fund to allow the other Railbelt utility customers to receive a fair share. The Administration took no position on the appropriations during the legislative session and made no recommendations as to how the fund should be appropriated.

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3/5/02

Susitna Hydropower

Introduction

Chugach management has requested a review of the Susitna hydropower project with particular emphasis on ways that the project could be scaled down to better meet the financial capabilities and operational characteristics of Chugach and the rest of the Railbelt utilities. The following text is based on available public archives, and no attempt has been made to update that information for comparative analysis with today's energy options.

Synopsis

Susitna was evaluated in depth by the State of Alaska in the early 1980s, and the State subsequently submitted an application to the Federal Energy Regulatory Commission (FERC) for a license to construct the project. The license application was withdrawn in 1985 when the price of oil dropped, thus impacting the economics of the project and the ability of the State to provide a significant portion of the project's construction funding.

If developed, the Susitna hydropower project would be centrally located between Anchorage and Fairbanks (Figure 1) and would be capable of providing 1,620 MW of power and 6,800 GWH of electricity to the Railbelt region by way of two high head dams and power plants on the Susitna River. The original concept for development of Susitna's hydropower potential was conceived by the Bureau of Reclamation in the mid 1900s. The Bureau scheme would entail four large dams to be constructed on the main stem of the upper Susitna River, upstream from the Gold Creek railroad bridge. The concept was later optimized to its present two-dam scheme as a result of detailed investigations by the U.S. Army Corps of Engineers in the mid 1970s and later the State of Alaska in the early 1980s at a c. st of $134 million.

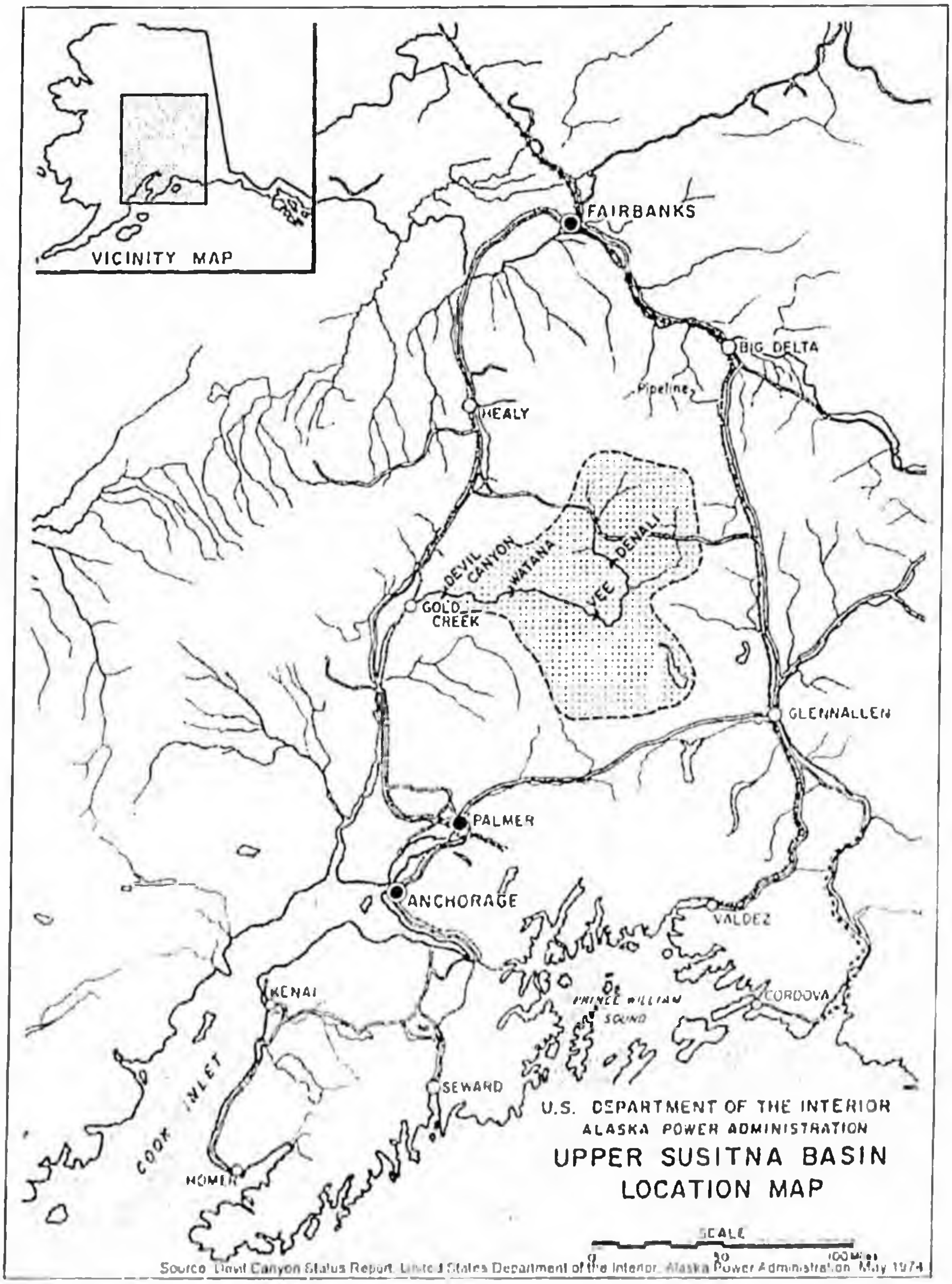


Figure 1 – Susitna Project Location

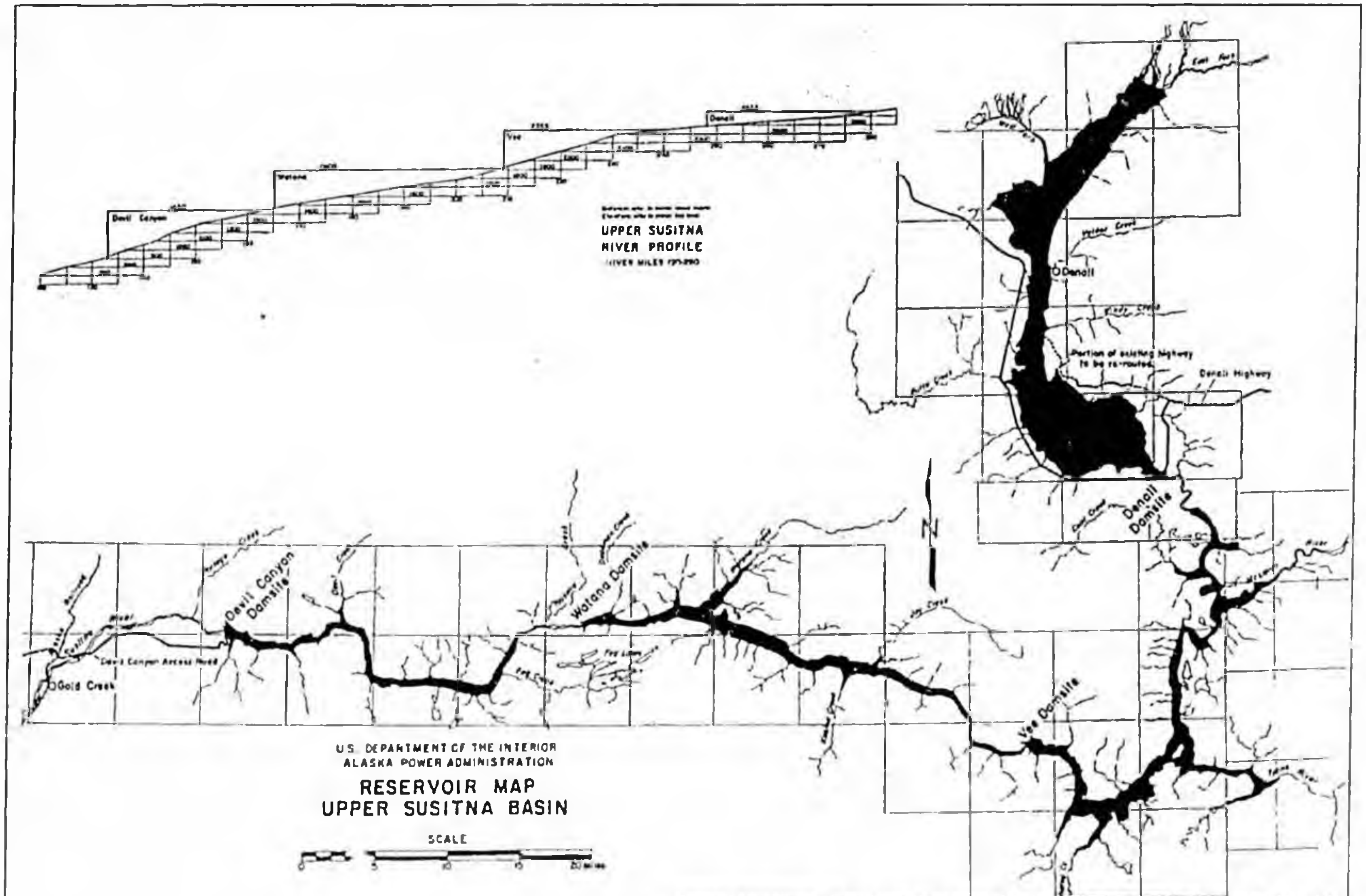
Because it was recognized that the first block of power from the project would be very expensive if totally debt financed, the State made a commitment to an equity contribution that was sized to offset this huge up front cost. This State contribution formed the heart of what was termed in Alaska Statute at the time as "The Energy Program for Alaska." Other elements of this program included all other projects developed by the Power Authority rolled into a single mechanism that would result in a "postage stamp" electric rate benefiting all utility customers of the state.

Although not developed, the Susitna project spawned the Anchorage-Fairbanks transmission intertie, the Bradley Lake hydropower project, and the Railbelt Energy Fund. The project remains technically viable and could realistically provide its full block of power for the next 200 years and probably much longer.

The Evolution of the Susitna Project

The energy potential of the Upper Susitna was first reported by the Bureau of Reclamation in a 1948 reconnaissance report. Then in 1950, the U. S. Department of the Interior provided funding to the Bureau of Reclamation to conduct studies that served as the basis for legislation to develop select water resources of the territory of Alaska. The Bureau's report identified numerous hydropower projects throughout Alaska but focused on Susitna because of its key location in the populated southcentral part of the state. The Bureau became enamored with dam sites in the precipitous terrain of upper Susitna river basin, starting some 45 miles upstream of Talkeetna.

The Bureau Four-Dam Scheme -- In 1961 the Bureau recommended to Congress the development of an ultimate four-dam scheme (Figure 2) with a first stage development consisting of Devil Canyon dam in th wnstream reach of the upper Susitna River, and a storage project at the Denali dam site 112 river miles farther upstream from Devil Canyon. As energy demand in the Railbelt was projected to grow, the Bureau anticipated recommending to Congress a third dam, named Watana, at the toe of the Devil Canyon reservoir, and then a forth dam, named Vee, at the toe of the Watana reservoir. Vee would be built to an elevation that would allow its reservoir to stretch back to the toe of



Source: Devil Canyon Status Report, United States Department of the Interior, Alaska Power Administration, May 1974

Figure 2 – Susitna Four Dam Scheme

the Denali dam. Thus the ultimate Bureau concept for developing Susitna consisted of three hydropower projects and one upstream storage project for a total river inundation of 135 lineal miles. The 4-dam Bureau scheme would be capable of generating 6,500 GWH average annual energy.

The Corps Rampart Project -- At about that same time, the Bureau's Susitna project got upstaged by the U. S. Army Corps of Engineers' more ambitious proposal to build a single giant dam on the Yukon River at Rampart. The Rampart project would be capable of generating five times as much energy as the 4-dam Susitna basin development. The Rampart concept captivated Senator Ernest Gruening and the public, thus shelving the Susitna project for the next 10 years while the Rampart project was evaluated further. Not only was Rampart found to be way too large for the Alaska market, but its potential environmental impacts were enormous. The reservoir would have taken 17 years to fill and would have covered an area the size of Lake Erie, destroying an incredibly large water fowl nesting area and wildlife habitat and blocking passage of anadromous fish that normally migrated deep into Canada. The volume of water in the reservoir would be enough to inundate the entire state of Texas with seven feet of water. There was serious concern that this large heat sink deep in Alaska's interior would melt permafrost, stimulate reservoir induced seismicity, and change weather patterns.

The Corps Two-Dam Susitna Scheme -- Finally, in 1972, Senator Mike Gravel succeeded in getting Congress to include legislation in the U.S. Senate Public Works Committee for the Corps of Engineers to take a new look at the Susitna project. The Corps came up with a new approach to Susitna. It found that by raising the height of the second upstream dam, Watana, an additional 350 feet over the Bureau's 410 foot dam , it could take advantage of the much broader canyon cross-section of the Susitna River upstream from Watana, thus, significantly increasing the storage capacity of Watana, flooding out the Vee dam site, and obviating the need for the Denali storage project. Thus, in one fell swoop, the Devil Canyon – High Watana scheme would develop more power than the Bureau's 4-dam scheme, at a lesser cost, and with less impact to the environment. The Corps' two-dam scheme would inundate only [illegible]0 miles of the Susitna River, but more importantly its reservoir would flood only 58 percent as much area as the 4-dam scheme.

In 1976, the Corps concluded that the project was economically superior to all future energy scenarios for the Railbelt and recommended that Congress appropriate funds for the projects engineering and design.

Tne State Takes Over -- Senator Mike Gravel, sensing that Congress was getting out of the hydropower development business and that Alaska was being perceived as the future "blue eyed Arabs of the North," proposed a novel federal/State partnership for Susitna's development that would capitalize on the Corps' dam building expertise, but using State dollars to fund the project.

The 1976 Alaska State Legislature responded by creating the Alaska Power Authority for that purpose. However, it did not limit the Power Authority's purview to Susitna, and ultimately the Authority was responsible for most of the new hydropower developed throughout the State in the 1980s.

The Power Authority quickly became leery of its shotgun marriage with the Corps and chose to pursue the project on its own in 1979. Using State of Alaska appropriations and private engineering firms, the Power Authority embarked on detailed feasibility studies and applied for a Federal Energy Regulatory Commission license to construct the project. After a $30 million feasibility study, the Authority concluded that indeed the Devil Canyon – High Watana two-dam scheme was the optimum project for the Railbelt at a 1982 construction cost of $5.5 billion. It then hired a new engineering consortium to thoroughly investigate all aspects of the project including detailed environmental, geotechnical, engineering and economic assessments. This culminated in the 1984 submittal of a FERC license application to construct.

Although the State actually started appropriating large sums for its equity contribution to the project, the "window of opportunity" slammed shut when the international price of oil plummeted from $34 per barrel ($83 per barrel in 2006 dollars) down to below $9 per barrel in the mid 80s. Thus, not only were all of the economic assumptions that drove the project nullified overnight, but the surplus cash flow needed by the State to fund its equity contributions entirely dried up. The State's FERC license application was withdrawn, and the project was shelved altogether in 1985. The funds previously appropriated for Susitna were reserved in the "Railbelt Energy Fund".

The Devil Canyon – High Watana Project

Prior to initiation of field studies and FERC license application for the two-dam Devil Canyon - High Watana scheme, the Alaska Power Authority spent approximately $30 million on alternative studies. The studies focused on the Susitna basin with various permutations of dam locations and dam heights to find the optimum development of the basin's potential. In addition to these investigations, the Power Authority also conducted assessments of other energy projects that could be constructed (see non-Susitna alternatives, below) and which would comprise the "yardstick" against which to measure the optimum Susitna project. Later, FERC staff conducted similar independent assessments during the licensing phase of the project.

Power Authority and FERC studies concluded that, based on load projections at the time, Cook Inlet natural gas would begin to run out by the turn of the century, and that coal-fired generation would be the next increment of power for the Railbelt if left to the financial resources of the utilities. However, financing aside, net present worth analysis found the Devil Canyon – High Watana hydropower to be economically superior to all of the alternatives – Susitna and non-Susitna (including coal-fired generation). The ability to finance the Susitna project was the limiting factor. Individual electric utilities were not envisioned to have access to financing of the magnitude required to develop the project, and a large State equity contribution was viewed as essential. Whether the economic advantage of Susitna over coal would hold today, given advancements in the coal technology and the potential of an export market form the Cook Inlet fields, is an open question. However, all studies at the time concluded that the Devil Canyon – High Watana two-dam scheme was the best long term plan for meeting the future electrical energy needs of the Railbelt.

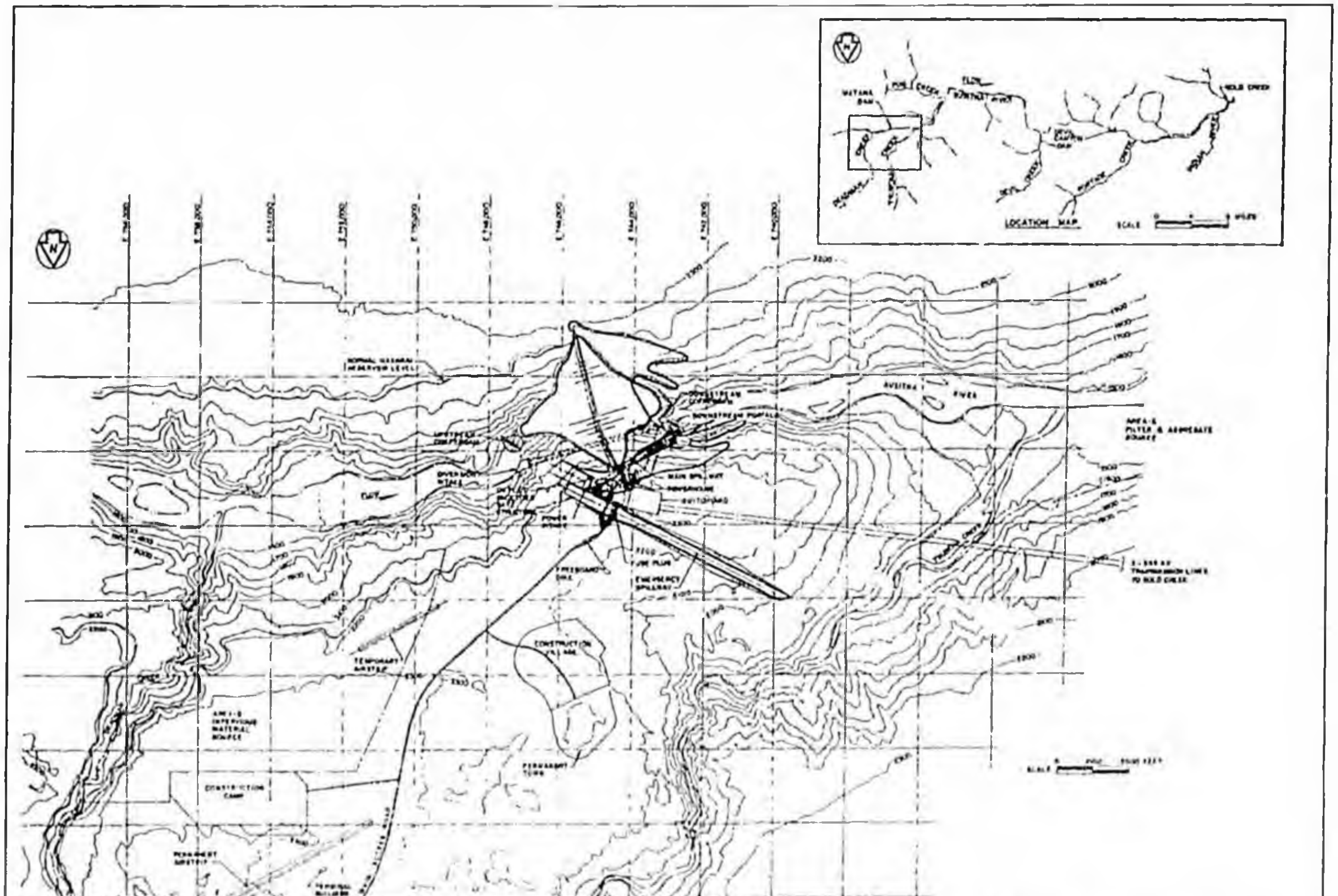
Optimum Full basin Development -- The Power Authority's proposed Susitna development scheme would have Watana built first and then, as demand dictated, Devil

Canyon would follow years later. In some respect this is the Achilles heal of the two-dam scheme. Watana is a much larger project than Devil Canyon, but the success of the two dams project depends on the capacity of the upstream Watana reservoir -- roughly ten times that of the Devil Canyon reservoir. Collectively the two projects would have an installed capacity of 1,620 MW. If Devil Canyon were built first, it would largely act as a very tall run of the river project and be capable of generating only 900 GWH annually. With the limited storage capacity of Devil Canyon, most of the summer freshet energy would be wasted. But, with Watana upstream providing reservoir capacity for both projects, the firm annual energy of Devil Canyon becomes 2,800 GWH spread evenly throughout the year more closely matching the composite Railbelt utility load curve. Power from both of the projects would be brought to the Anchorage and Fairbanks load centers by way of a double circuit double tower 345 KV transmission system, a portion of which was constructed in 1983. Watana is the more expensive of the two projects, but its increment of generation would be 1,020 MW, a very large initial component for the Railbelt utility system to absorb.

The following paragraphs briefly describe each of the two elements of the High Watana – Devil Canyon project.

High Watana -- Watana would be an 885 foot high rock fill dam with an impervious core, located at river mile 184, approximately 2 5 miles upstream of the Tsusena Creek confluence. Figure 3 shows the basic elements of the project. The crest length of the dam would be 4,100 feet long and the total volume of the structure would be approximately 62 million cubic yards. Watana would create a reservoir 48 miles long with a surface area of 38,000 acres and a total storage capacity of 9.5 million acre-feet. Maximum reservoir drawdown would be 120 feet for a live storage of 3 7 million acre-feet.

The power house would be located underground on the north bank of the river and would house six 170 MW Francis turbines. Flow to the power house would be by way of six concrete lined 17 foot diameter penstocks with inflow control provided by a concrete multi-gate intake structure.



Source: Susitna Hydroelectric Project Draft Environmental Impact Statement, Federal Energy Regulatory Commission, May 1984

Figure 3 – Watana Facilities Plan

Three separate outlet structures would have the capability of passing the 50-year, 10,000-year and probable maximum floods respectively. Construction of the project would be carried out over a nine year period and require a construction camp capable of housing 3,300 workers and a permanent town capable of housing 130 operations workers for both of the projects. The total cost of Watana was estimated to be $4,062 million (1982 dollars).

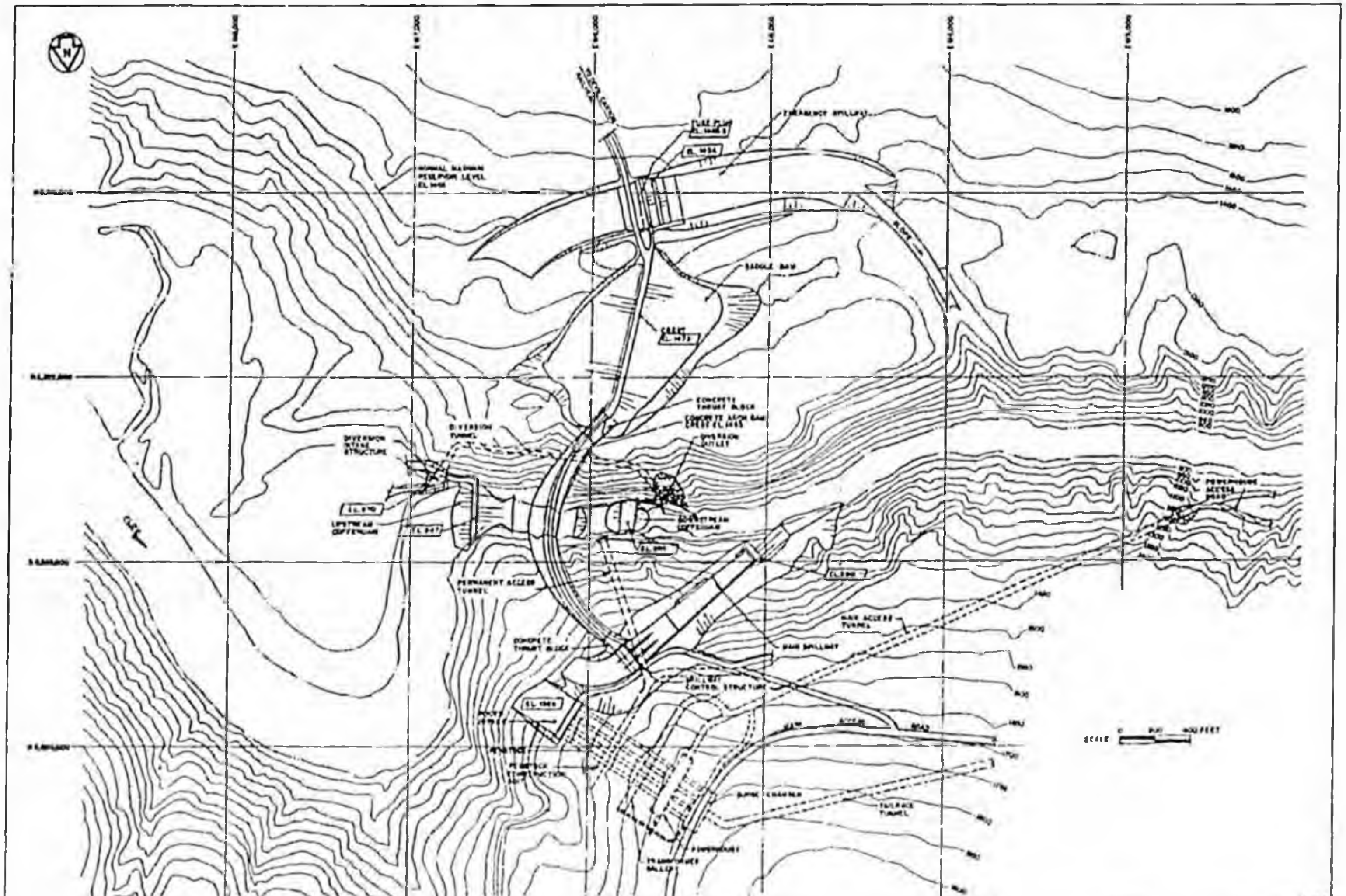
Devil Canyon -- Devil Canyon would be a 646 foot high double curvature thin arch concrete dam located at river mile 152 on the Susitna River, approximately 14.7 miles upstream from where the Alaska Railroad crosses the river at Gold Creek and approximately 32 river miles downstream from Watana. Project development would be timed to meet growing energy demand in the Railbelt. Upstream Watana would not be physically or economically dependent on the ultimate development of Devil Canyon, and Devil Canyon could be delayed indefinitely. The thin arch structure (Figure 4) would tie into gigantic thrust blocks on each abutment. A 245 foot high rock fill saddle dam would be tied into a south bank concrete thrust block, providing closure to higher terrain.

The Devil Canyon would form a 26 mile long reservoir with a surface area of 7,600 acres and a storage capacity of 1.1 million acre-feet. Appurtenant structures would be designed to accommodate a 50 foot reservoir drawdown yielding a live storage capacity of 350,000 acre-feet. However, because of the massive storage capacity upstream at Watana, Devil Canyon would be operated at its full pool elevation to maximize the project's head. There would rarely be a need to draw down the Devil Canyon reservoir.

The project would include an underground powerhouse in the north abutment housing four 150 MW Francis turbines for a total installed capacity of 600 MW. As with the Watana turbines, the Devil Canyon turbines would have a 15 percent overload capability.

Devil Canyon would take six years to construct and would require a camp capable of housing 1,800 workers. Total estimated cost of Devil Canyon is $1,503 million (1982 dollars).

Site Access -- There is no surface access to the two dam sites at the present time. Nearest access is by way of the Denali Highway, which traverses the basin about forty



Source: Susitna Hydroelectric Project Draft Environmental Impact Statement, Federal Energy Regulatory Commission, May 1984

Figure 4 – Devil Canyon Site Layout

miles north of the two dam sites, and the Alaska Railroad, which crosses the Susitna River at Gold Creek, 14.7 miles downstream from Devil Canyon.

Access to the Watana site would include a new railhead at Cantwell, where a 40 acre lay-down yard would be constructed. From there, road access would be by way of 22 miles of existing road along the Denali highway and then 41 miles of new road to the dam site. A permanent airfield would be built at the Watana site to accommodate construction and eventual operation of the project.

From the Watana camp, a suspension bridge would cross the river downstream from the dam site, and a new road approximately 20 miles long would connect to the Devil Canyon site. In addition, a new railroad spur would be built from Gold Creek to the Devil Canyon Site.

The Alaska Department of Fish and Game anticipated controlled access to the sites, but it is probable that the recreation value of the sites would be such that public pressure to gain access to the sites would prevail.

The Upper Susitna Environment and Project Impacts

The Upper Susitna river basin comprises an area of approximately 6,160 square miles and supports an average annual stream flow at the basin outlet below the Devil Canyon dam site of approximately 6.5 million acre-feet. Summer stream flow is roughly ten times that of winter flows. The basin is bordered on the north by the Alaska Range, the Talkeetna Mountains to the southwest, and flat low relief areas to the southeast. By the time that the river enters the Cook Inlet, it has grown to be the sixth largest river in Alaska and is supported by an entire drainage area of approximately 19,000 square miles.

<u>General characteristics</u> -- A description of the upper Susitna area is described in the June 1978 Corps of Engineers Plan of Study (written earlier by E. Yould when employed with the Corps):

> "Most of the basin has a well-defined branching stream pattern with a main channel emanating from glacial headwaters in the extreme northern segment of the divide. Below the glaciers, the braided stream traverses a high plateau

composed of aggraded alluvial sediment, and then meanders several miles south to the confluence with the Oshetna River. It then takes a sharp turn to the west and flows through a steeply cut, degrading channel until it exits the basin at Gold Creek. The contributing glacial area comprises only 4 percent of the entire basin, but summer glacial melt provides a considerable portion of the total stream flow. By contrast, the flat, glacially carved Lake Louise area in the southeastern portion of the basin provides comparatively little flow from its 700-square-mile area.

The mountains within the basin reflect the influence of the Pleistocene Ice Age, during which glacial advancement over the topography planed the mountains and gave the basin surface a rounded and smoothed appearance. The highest elevation within the basin is 13,326 feet, and the lowest elevation is 740 feet. The basin relief implies a steep channel slope; however, variability of the slope compared to other mountain streams is somewhat reversed. The aggraded channel in the upper reaches of the basin has channel slopes in the range of only 4 to 7 feet per mile while the lower basin channel [where Devil Canyon and Watana would reside] drops as much as 37 feet per mile. The deeply incised river channel below the Tyone River contrasts with the many traditional Alaskan U-shaped valleys remnant of glacial advances."

Field Investigations -- In 1980 the Alaska Power Authority established a 100 person field camp at the Watana dam site for the purpose of supporting field crews investigating aspects of the project. The camp was brought in during the winter time by way of low pressure tire "rollagons." In addition to the mobile camp at Watana, tent camps were established at strategic locations throughout the basin. During the 1981 and 1982 field seasons, numerous biologic, geologic, seismic, and fish and wildlife investigations were performed both in the area directly impacted by the projects, and downstream. Extensive sonar and physical fish counts were conducted during this period. Wildlife inventories were conducted from the air, and detailed flora and fauna investigations were performed by scientists on test plots and from the air using infrared technology.

Fish -- All five Pacific salmon species spawn in the Susitna drainage. However, the strong hydraulic current in the 75 mile canyon stretch of the river above Gold Creek prevents anadromous fish from ascending the drainage basin above the point in the river where the dams would be built. In contrast, the habitat downstream of the project sites supports a fishery that is heavily harvested by commercial, sport, and subsistence users. While the dams may not directly impede migration of salmon into the upper basin, post project physical changes to the flow regime below the projects would impact the downstream fishery. Impacts would attenuate at locations farther downstream from the dams as the moderating influence of the rest of the basin begins to dominate project releases. Impacts would be a result of significant change to the water temperature, and its resultant impact on salmon fry of those species that winter over before migrating to the ocean. Impacts would also accrue from a loss of fish rearing habitat due to increases in turbidity during reservoir filling and from stream channelization and a loss of side sloughs resulting from the diminution of normal peak runoff events. There would also be the infrequent impact that fish may suffer from nitrogen supersaturation that could occur during spillway bypass events.

Conversely, through mitigative measures the dams also would provide the opportunity to open up the otherwise unused habitat above the dam sites for salmon spawning and rearing. There was also the potential to establish a world class fish hatchery below the project sites that could help transform the Cook Inlet fishery into a world class resource. These mitigative or enhancement measures were not included as part of the FERC license application.

Seven resident fish species were found throughout the Susitna basin including the impoundment stretch of the river. The project would directly impact habitat of the resident fish populations in the impoundment areas as well as downstream from the projects. As with the salmon species, these impacts would attenuate with distance downstream from the project sites.

Absent fish hatcheries or propagation of salmon spawning habitat in the basin above the dam sites, ultimately FERC staff concluded that is was "not possible to assess whether the Susitna Hydroelectric project would result in an average long term decrease or increase in populations of salmon presently spawning in the Susitna River Basin." FERC did conclude that there would be a loss of anadromous fish during the initial filling of the Watana reservoir. Resident fish impacts would largely be confined to direct loss of main stem habitat in the area of the dams and reservoirs, and shifting of these fisheries to higher elevation lake type environments associated with the project's reservoirs.

Wildlife -- Field inventories indicated that the upper Susitna and project site supports a diverse wild life typical of southcentral Alaska, including big game animals, fur bearers, various bird species, and small mammals. Except for the peregrine falcon, which uses the upper basin as a flyway, no endangered species were found. However, project features and reservoirs would permanently withdraw habitat from use by various key wildlife.

Moose are the most important large animal species in the Susitna basin that would be affected by the project . An estimated 2,200 moose in the project area would be directly impacted, and as many as an additional 9,000 moose could be indirectly impacted.

The Nelchina caribou herd, with an estimated population of 20,000, ranges throughout the area, but their total habitat is much broader, extending throughout the Copper River Basin. As such, the project would create little direct impact on the herd. Brown bear would suffer a small loss of denning habitat and could have some of their range patterns inhibited by the reservoirs. They would also loose some moose predation in the reservoir areas. Black bears could be the most impacted large mammal species in the upper Susitna basin, as a large amount of their lowland habitat adjacent to the Susitna River would be lost. The studies estimated that 55% of known black bear dens would be inundated by the reservoirs.

Dahl sheep, wolves, raptors, water fowl, and other indigenous wildlife would experience various levels of stress from the project. Enhanced hunter access would put more pressure on all big game species and birds in the basin, as would be the case for the fisheries as well.

Alternatives to Susitna

Certainly the Railbelt utilities had the capability to develop coal alternatives, but it was probably only a State sponsored effort through the Alaska Power Authority that a capital intensive renewable energy project such as hydropower, geothermal, or tidal power could be realized. Thus, to ensure that the two-dam scheme was the best non-thermal alternative for the Railbelt, the Power Authority and later FERC, looked at a number of energy alternatives and even attempted to assess the cumulative impacts of some of the more promising alternatives. Not only did the alternative studies substantiate the economics of Susitna, but they also allowed the assessment of the cumulative impacts that would occur if Susitna were not built. Environmental groups often make a compelling argument regarding the adverse environmental impacts of a Susitna or similar type project, but they rarely address the adverse impacts that would accrue if the project were not built.

Geothermal studies focused on areas near the Railbelt that contained hot igneous systems. These included Mt. Drum and Mt. Wrangell in the Copper River basin, and Mt Redoubt (Double Peak) and Mt. Spur in the Cook Inlet area. Most of the geothermal studies were based on existing research by others, but ultimately all of the sites were found to be a) very expensive to develop, and b) lacking adequate exploration to prove up the resource. Little effort was made to assess the environmental impact that might be associated with any of the geothermal projects.

Tidal power received a more rigorous review. The legislature appropriated $500,000 over and above the Susitna funds to study the tidal power potential of the Cook Inlet area. The Power Authority, through its contractor, studied 16 sites throughout Cook Inlet area with cumulative energy potential exceeding 168,000 GWH. The Power Authority developed conceptual designs for each site and reconnaissance level cost estimates. A site at Sunshine, on Turnagain Arm, was found to be the best site for tidal power, but the economics of this alternative were inferior to the Susitna hydroelectric project, and environmental impacts to fish and whale blockage were deemed potentially significant.

The Power Authority also looked at solar power, peat, and non-structural alternatives such as energy conservation and load management. It also considered many of these alternatives as part of coal and natural gas scenarios but later rejected them as inferior to Susitna.

The non-thermal alternative that received considerably more attention than those mentioned above was that of non-Susitna hydropower alternatives. The Power Authority identified 91 potential hydro sites available to the Railbelt market. After four screening iterations, the Authority narrowed these sites down to the most promising 18 sites and ranked them according to environmental impact and economic attractiveness. FERC staff later selected the top five from this list and evaluated them in depth individually and in combination against the Susitna two-dam scheme. The following table is a summary of the hydropower projects selected by FERC for more detailed comparative analysis.

Alternative	Estimated total cost of project (Million $, 1982)	Total installed capacity (MW)	Average annual energy demand (MWH)
Johnson	319	210	929
Chakachamna	905	333	1,300
Snow	305	100	375
Keetna	519	100	420
Browne	681	100	418

No combination of these hydroelectric sites, even in conjunction with thermal alternatives, proved economically superior to the proposed Susitna plan, and many were predicted to have serious adverse environmental impacts. Some of these projects were even analyzed as though they were an element of a staged development of the Susitna project. For instance, in one analysis Chakachamna was considered as the second stage development of Susitna in lieu of Devil Canyon.

In summary, the Susitna two-dam scheme was found to be economically superior to virtually all energy alternatives on the basis of a 50-year net present-worth analysis. Once again, there is no guarantee that the outcome would be the same if the economic alternatives analysis were performed today:

- Capital costs have certainly changed with inflation as have the cost of building materials, not only for Susitna but for other alternatives, as well.

- Environmental protection laws and sensitivities have continued to evolve, generally becoming more restrictive.
- Cook Inlet natural gas has proved more abundant than was estimated in the Susitna studies, but its pricing is estimated to approach "Henry hub" levels within the next decade.
- More importantly, however, is the international cost of fuel that drives the shadow value of thermal alternatives to Susitna. In 1984, FERC estimated that the real cost of oil would escalate at one percent over inflation and that this would drive the cost of natural gas.
- The cost of coal was not projected to escalate at this same rate as oil, as there was not viewed to be a significant export market for coal. In fact, in retrospect, the price of oil in real dollars was higher in the early 1980s than it is today at $70 per barrel. Cook Inlet coal, on the other hand, is showing signs of establishing an export market and its cost will likely break out of its historical flat trend.

Could Susitna be Scaled Down?

Like all of the Railbelt utilities, Chugach management is attempting to assess what generation can best serve its customers' needs in the foreseeable future. Natural gas availability is projected to decline, and the cost is likely to rise. North Slope natural gas may become a reality, but there is no guarantee that it will be economically feasible to bring a spur line to the Cook Inlet area. Coal may well become more available, but the capital cost of coal generation facilities is high. In addition, the cost of mined coal may escalate with increased global market demand. Chugach has experienced the benefits of hydropower options such as Cooper Lake, Bradley Lake and Eklutna, but no other such options are being considered for the Railbelt at this time. Other renewable energy options such as Fire Island wind generation may prove beneficial, but such options cannot be expected to meet Chugach consumers' base load needs.

Susitna could meet all of the needs of Chugach, but does it represent a realistic option? Susitna is very large, very expensive, and requires a long lead time to develop. However, much of the front end work has already been done by the State of Alaska. It is possible that a revised FERC license application to construct the project could be crafted from the State's earlier FERC submittal. Putting aside some of the institutional questions at this time, could Susitna be reformulated to better meet the needs of Chugach and the Railbelt?

Reformulate Susitna -- If it can be accepted that the Devil Canyon – High Watana scheme is the optimum basin development, then it must be realized that any deviation from this scheme will have an economic penalty. On the other hand, a scaled down version of the project may still prove economically superior to other non-Susitna options but better fit the present and near term load characteristics of Railbelt utilities and be more readily financed. Therefore, ignoring the issue of whether Susitna would still be the superior choice for the long term needs of the Railbelt, what are some of the changes that can be made to the Susitna project to make it more amenable to development at this point in time?

The following is a subjective review of changes that could be made to the project. Full review would require formulation of new cost estimates and reservoir regulation analysis to test the sensitivity of options.

Build Watana in Two Stages

The Power Authority actually analyzed this possibility but rejected it for economic reasons, i.e., the full project fared better in the net present worth analysis. Watana would first be built to a height of 450 feet and increased to its full proposed height of 880 feet later, as demand dictated. Under this scenario, the first stage development would be burdened with a design that would accommodate the larger ultimate development. In addition, the shorter dam would still need a spillway fully capable of passing the probable maximum flood. This spillway would then be abandoned in deference to the ultimate spillway that would accommodate the higher dam. The cost of the oversized powerhouse and all hydraulic works would accrue to the smaller project. Not only would this impart an economic penalty on the first project built, but if for some reason the second phase were not built, the large storage capacity available in the upper elevations would be forgone limiting the economic benefit of Watana as well as a subsequent downstream Devil Canyon dam. One advantage of building in this fashion, however, is that it would not foreclose the possibility of building Vee and Denali upstream in lieu of the higher Watana. It must be recognized that it is still an open question, raised by the Power Authority, whether or not Denali is a viable dam site.

Build Devil Canyon First

As discussed earlier, the Devil Canyon cost was estimated to be $1.5 billion as compared to Watana's $4.0 billion price tag. However, by reversing the order of construction, many of the initial project features originally allocated to Watana (as a first project built) would now be part of the Devil Canyon development cost. At a minimum, this would include access roads, camp facilities, transmission lines, and hydraulic works to accommodate floods that might otherwise not occur with Watana upstream. In addition, river closure at Devil Canyon would entail a significantly increased structural work without Watana upstream, resulting in higher project costs. As a general rule, it is always best to build upstream projects first, as these structures can then help control the river during closure for subsequent downstream projects. In reverse, each closure upstream of a dam is every bit as complex as the first dam built.

This option also suffers from the limited storage capacity at Devil Canyon. As part of the two-dam scheme, Devil Canyon could generate 2.8 billion KWH firm annual energy, but as a first project built, Devil Canyon's inability to store water during the summer would be such that its firm annual energy would be only 900 million KWH. In essence, it would be a high head run-of-the-river project. If Watana were never built upstream, it would be an open question as to whether Devil Canyon would ever pay for itself. A complicating factor would be the annual sediment load of the Susitna River and its impact on Devil Canyon's storage capacity. The average annual sediment load flowing past the Devil Canyon site is estimated to be 5,000 acre feet per year. Over a one hundred year period of time, assuming that Watana were not built upstream, and further assuming a 100% trap efficiency, the Devil Canyon reservoir would become almost fifty percent filled with sediment. Most of this sediment would filter out in the active storage zone, further reducing the amount of summer storage available to firm up annual power generation.

Build a Series of Smaller Projects

This option holds the greatest promise for finding a scaled down basin development that can better meet the demands of Chugach an Railbelt utilities. In its studies, the Power Authority actually looked at 11 different dam sites in the upper Susitna basin. It even looked at one scheme that would include High Watana with a 30 mile power tunnel and the elimination of Devil Canyon. Environmentally, this was found to be a superior scheme, but it certainly did not lend itself to staged development. Unfortunately, the Power Authority eliminated the Denali site as a potential project. This decision needs to be revisited. With Denali storage upstream, any number of smaller projects could be built downstream, with each dam being built at the maximum reservoir elevation required to facilitate the next downstream project. There are a number of dam sites that could be evaluated in the 90 mile stretch of river upstream from Gold Creek. There would naturally be a tradeoff between multiple small dams and, for instance, the original Bureau of Reclamation 4-dam scheme consisting of Devil Canyon, Watana, Vee and Denali. Without a Denali or High Watana type project, numerous small projects on the main stem of the river would act primarily as run-of-river projects. The almost 7,000 cubic feet per second (cfs) average annual stream flow that presently flows past Gold Creek would occur in the ratio of about 20,000 cfs summer flow to 2,000 cfs winter flow. Without upstream storage capacity, much of this summer flow would go unused. If Chugach and the other Railbelt utilities were seriously interested in revisiting Susitna, the first order of business would be to review the viability of Denali as a legitimate dam site. If Denali is determined to be viable, it would then be prudent to reassess the original 4-dam scheme, or perhaps a series of smaller projects in the Gold Creek to Vee stretch of river.

Steps to Bring a Scaled Down Susitna to Fruition -- As originally envisioned by the Power Authority, Susitna hydropower could be an excellent long term option for Chugach and the rest of the Railbelt utilities. However, Susitna has some obvious drawbacks:

- It is a very capital intensive project.
- Although it may be shown to be the economically superior option for Railbelt utilities, the initial cost of power, if debt financed, would probably be significantly higher than the existing cost of power.
- It is beyond the ability of the Railbelt utilities to finance.

- Even if the financial and economic issues could be adequately addressed, it would require the total commitment of all of the Railbelt utilities to bring the project forward.

For these and other reasons, it would appear that the only realistic option for reconsidering a Susitna project is through some sort of partnership with the state government. The defunct Alaska Power Authority would need to be reconstituted from the existing Alaska Energy Authority, or a separate Authority could be established specifically for developing Susitna. Alternatively, if properly structured, the utilities may conclude that a G&T or JAA could serve as the organizational structure to bring the project forward, perhaps in partnership with the State. At any rate, the implementing organization would need the singular focus of bringing Susitna forward. It would also be absolutely imperative that all of the Railbelt utilities were in agreement that the project should go forward. Active dissent would torpedo any efforts to enlist Legislative appropriations for the project.

The State currently has $34 billion in the permanent fund, a surplus source of revenue, and the prospect for an even greater source of revenue if the North Slope natural gas pipeline is constructed. A portion of these funds could be dedicated to a substantial equity contribution to a Susitna project or some other financial mechanism to reduce to cost of power sold to consumers in the early years after the project starts generating power. The State could look at the project as the "bricks and mortar" equivalent of the Permanent Fund, with the benefit flowing directly to Alaska citizens. There is even the option that the State could be paid back some or all of any contribution that it were to make to the project at such time that inflation diminishes the impact of the front end cost of the project. There is increasing pressure to curtail worldwide carbon emissions, to develop renewable resources, and to decrease dependence on foreign oil. Few countries or other states have a Susitna project in their backyards. With the high cost of oil, changing public attitudes toward energy consumption, and prospective financial resources of the State of Alaska, there may well be a window of opportunity opening up for development of Susitna -- if Chugach and the other Railbelt utilities choose to pursue it in earnest.

YOU'RE THE MASTER; THIS IS YOUR UNIVERSE

TOMORROW'S SMART GARAGE IS READY TO OBEY YOUR EVERY WHIM

PAUL KENDALL

The garage of the future will still shelter your car and serve as a place to store your lawn mower and other indoor-outdoor equipment. But according to visionaries we interviewed at organizations ranging from the Ultimate Garage to the Electric Power Research Institute, in 10 years your garage will also be a savvy service center. Multiple power systems will ensure that your house consumes—and generates—energy as efficiently and inexpensively as possible. A team of robots will automatically take out the trash, accept and sort deliveries and trim your lawn—but only if it needs it. And sensors will valet park your vehicles and keep tabs on their condition. All you'll have to do is sit back and enjoy the ride. —CHARLES WARDEN

July - 2004 Pop Science pg 21

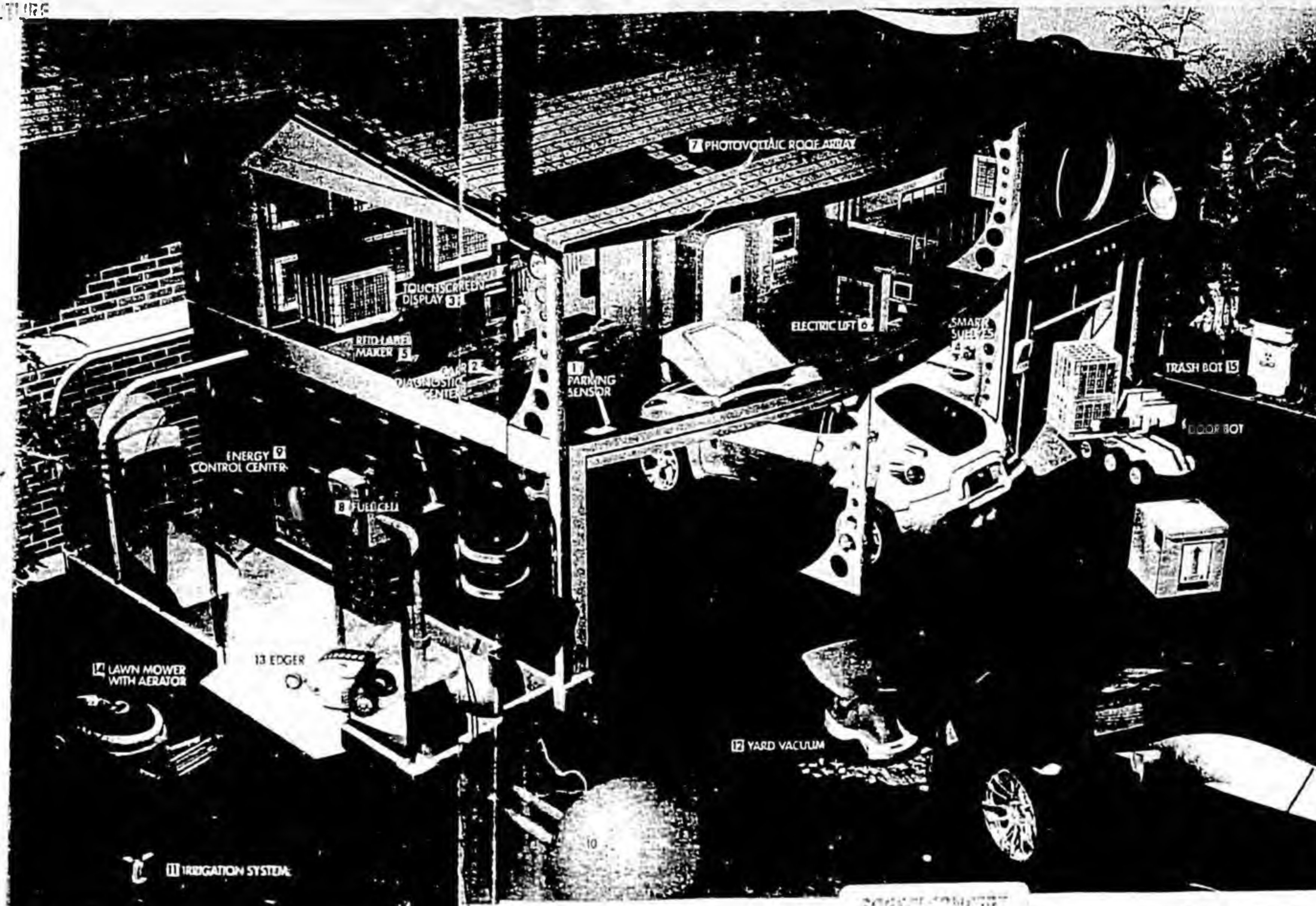
Pull up to your garage, press the park button ... beams help your car guide itself into ... [1]. Once parked, your car transmits ... diagnostic station in the garage ... the system's display tells you when it's time for regular maintenance—like a 300,000-mile tune-up—and warns you if something needs attention, presenting all your options. If you're handy, use the touchscreen [3] to display your car's manual, and order parts if necessary; it will then walk you through the repair. If you'd rather not sully your mitts, beam the diagnosis to your repair shop for an estimate. The mechanics can use their own computers to do a more in-depth remote diagnosis and notify you if and when you need to bring it in. A handheld camera lets you send visual as well as electronic information.

SMART STORAGE Shelves [4] have built-in scales to keep track of how much fertilizer, grass seed and other lawn-care products you've used. They automatically scan Radio Frequency Identification (RFID) tags in product labels as items are removed and replaced and update the inventory on your home computer. An RFID label maker [5] lets you inventory the contents of your own storage boxes so you know exactly where you stashed the holiday decorations. To maximize storage space, all these boxes, as well as bikes, boats and other recreational toys, are stored on the second story with the help of an electric lift [6].

Your home will still be connected to the grid, but it will also include two of its own power-generating systems: a photovoltaic roof array [7] that can deliver energy directly to your home and a hydrogen fuel cell [8]. A central controller [9] coordinates these systems. When the sun is shining and you need power, the solar rooftop system supplies it. If it's a blue-sky day and nobody's home, the solar energy powers a reformer, which extracts hydrogen from water; the hydrogen is stored safely in a subterranean tank [10]. As a last resort, if it's cloudy and your fuel cell's out of hydrogen, the controller finds out through the Internet which utility has the lowest rates at that instant, and draws from the grid.

The irrigation system [11] goes online to check National Weather Service reports and municipal water restrictions, using the information to decide when to water. A small army of robotic lawn-maintenance tools can make decisions based on the same data, and automatically groom your yard accordingly. You'll have single-function bots like a yard vacuum [12] and edger [13], as well as a mower that takes attachments such as an aerator [14]. The bots rest on their charging stations between jobs.

A robotic trash can [15] sits on a charging station by the back door to the house. It has an automated routine to wheel itself to the curb on collection night.



Think of the door bot as a robotic porter. It stashes packages from the delivery guy. Once he keys in a one-time code and leaves your packages in a double-secure storage bay, the bot scans the embedded RFID tags and automatically puts the boxes on the correct shelf or in the fridge (or freezer). It finds and retrieves items for you from the second-floor storage room. And it fetches and puts away your tools.

Home Refueling Station — Reforming to Hydrogen via NAT GAS ELECTROLYSIS From Water Lines. Paul D. Kendall

Phill nat gas pump for home use by Fuel Maker — Available now!

Economic Independence — Paul Kendall

Pop Science July 2004 pg 21

YOU'RE THE MASTER; THIS IS YOUR UNIVERSE

TOMORROW'S SMART GARAGE IS READY TO OBEY YOUR EVERY WHIM

PAUL KENDALL

The garage of the future will still shelter your car and serve as a place to store your lawn mower and other indoor-outdoor equipment. But according to visionaries we interviewed at organizations ranging from the Ultimate Garage to the Electric Power Research Institute, in 10 years your garage will also be a savvy service center. Multiple power systems will ensure that your house consumes—and generates—energy as efficiently and inexpensively as possible. A team of robots will automatically take out the trash, accept and sort deliveries and trim your lawn—but only if it needs it. And sensors will alert you to your vehicles and keep tabs on their condition. All you'll have to do is sit back and enjoy the ride. —CHARLES WARDELL

July - 2004 PopScience pg 21

[illegible] Pull up to your garage, press the park button [illegible] beams help your car guide itself into [illegible] (1). Once parked, your car transmits [illegible] diagnostic station in the garage [illegible] The system's display tells you when it's time for regular maintenance—like a 300,000-mile tune-up—and warns you if something needs attention, presenting all your options. If you're handy, use the touchscreen (3) to display your car's manual, and order parts if necessary; it will then walk you through the repair. If you'd rather not sully your mitts, beam the diagnosis to your repair shop for an estimate. The mechanics can use their own computers to do a more in-depth remote diagnosis and notify you if and when you need to bring it in. A handheld camera lets you send visual as well as electronic information.

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HOME POWER SYSTEM Your home will still be connected to the grid, but it will also include two of its own power-generating systems: a photovoltaic roof array (7) that can deliver energy directly to your home and a hydrogen fuel cell (8). A central controller (9) coordinates these systems. When the sun is shining and you need power, the solar roofing system supplies it. If it's a blue-sky day and nobody's home, the solar energy powers a reformer, which extracts hydrogen from water; the hydrogen is stored safely in a subterranean tank (10). As a last resort, if it's cloudy and your fuel cell's out of hydrogen, the controller finds out through the Internet which utility has the lowest rates at that instant, and draws from the grid.

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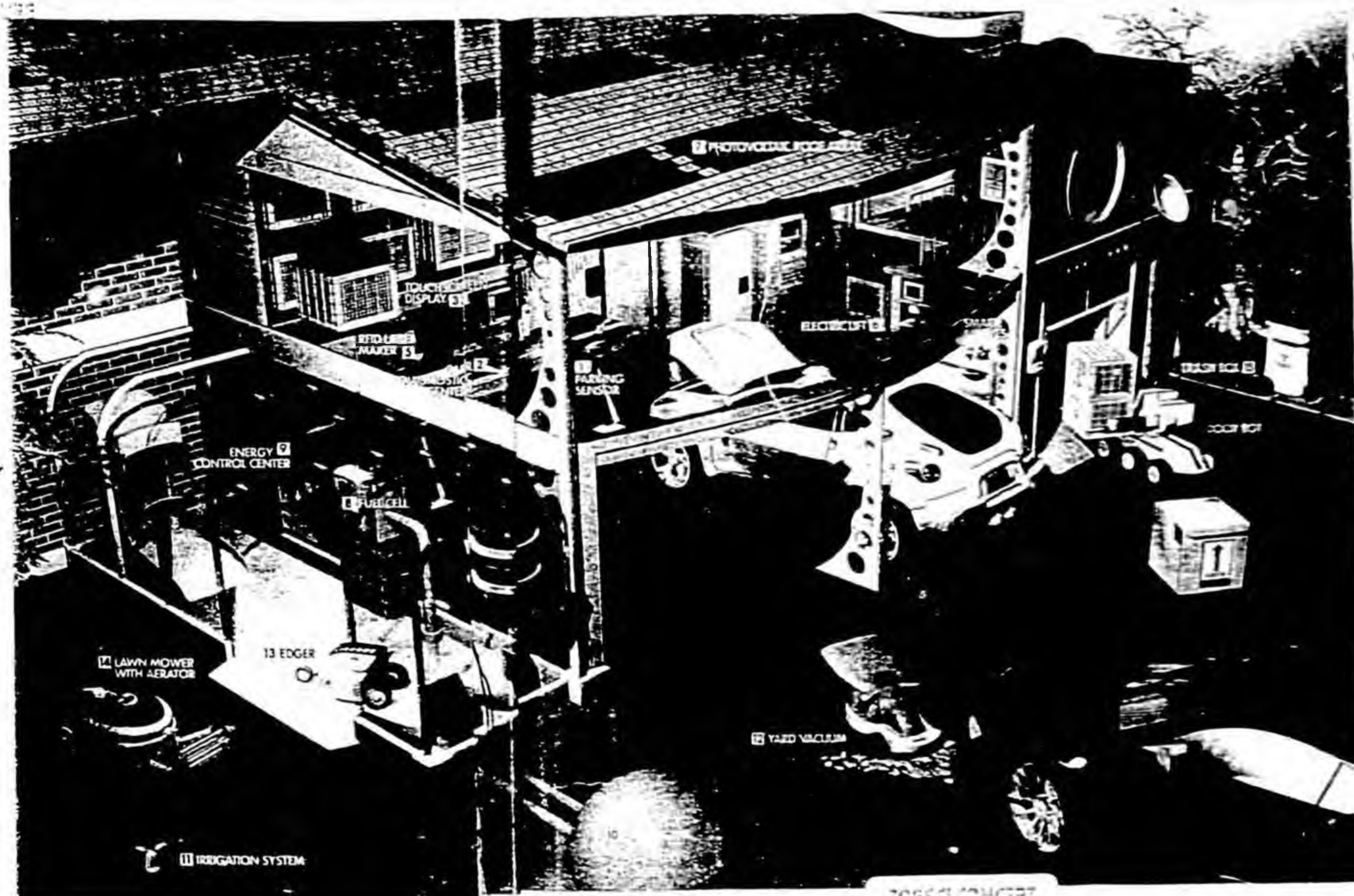
[illegible]



POPSCI CONCEPT

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— Home Refueling Station —
Reforming to Hydrogen via NAT GAS & ELECTRONICS
FROM WATER LINE.
Paul D. Kendall
Phill NAT GAS pump for home use by
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Hydrogen Fuel
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HYDROGEN USE IN ALASKA

Project 40902 Final Report

241 PAGES

Christopher F. Blazek
Timothy D. Donakowski
Martin Novil
Edward J. Daniels

A GREAT STUDY - OUTLINE - 1981

Prepared by
Institute of Gas Technology
IIT Center, 3424 S. State Street
Chicago, Illinois 60616

Date Published — November 1981

Prepared for the
U.S. DEPARTMENT OF ENERGY
And

STATE OF ALASKA

Under Contract No. DE-AC02-80CS91201

Table ES-1. DEMONSTRATION COMMUNITY COSTS

Stage of Project	Item	Size or Number	Cost,* $10^3
Preliminary Investigations	None	--	--
Field Studies	None	--	--
Offsite R&D	Appliance Testing	6 month	100
Demonstration Project			
Phase I	H_2 Storage	4×10^6 SCF	1,600
	Fueling Station	1	50
	Automobile Conversions	25	50
	Three-Wheeler Conversions	45	90
	Boat Conversions (gasoline)	25	50
	Boat Conversions (diesel)	15	300
Phase II	Alternate Wind Power System ($1100/kW + 60 Mills/kW hr)	220 kW	240
	Electrolyzers (current technology)	1600 SCF/hr	100
Phase III	H_2 Storage	35×10^6 SCF	8,000
	Distribution System	400 people	720
	Furnace Conversions	100	40
	Water Heater Conversions	100	15
	Range	100	15
Phase IV	Alternative Wind Power System	1900 kW	2,100
	Electrolyzers	14,000 SCF/hr	870
Phase V	Alternative Wind Power System	500 kW	550
	Electrolyzers	1500 SCF/hr	100
	H_2 Storage	260,000 SCF	280
	Fuel Cell System ($600/kW)	150 kW	90
Evaluation	None	—	—
		Subtotal	14,360
	Freight + Contingency (30%)		4.300
Support Staff			1,030
		Total	19,690

* Assumes 1 month storage.

COMPUTER IMAGE BY CHUCK CARTER

The world's water supply

If all earth's water fit in a gallon jug, available fresh water would equal just over a tablespoon—less than half of one percent of the total. About 97 percent of the planet's water is seawater; another 2 percent is locked in icecaps and glaciers. Vast reserves of fresh water underlie earth's surface, but much of it is too deep to economically tap.

Little Cyclones end seven-game losing skid

See SPORTS, C1

THE TRIBUNE

Paul O. Kendall

Where are our [redacted] leaders on this $?

Vol. 136 – No. 302 | AMES, STORY COUNTY, IOWA | Wednesday, June 23, 2004 50¢

Paul Kendall

Cutting-edge energy

Proposed wind and hydrogen plant for Ames would be world's first

By Beth Anderson
Staff Writer

The Ames Laboratory is proposing to build the world's first wind and hydrogen energy plant in Ames under a three-way partnership with the city and Iowa State University.

Tom Barton, the director of the Ames Lab, went before the Ames City Council Tuesday to seek support for a project that could provide inexpensive electricity for the city, be a source of hydrogen for research and place Ames in the international spotlight for renewable energy.

"It could be a win-win-win deal," Barton said.

The council unanimously approved a motion to move the project forward, directing staff to work with the Ames Lab.

The proposed project would erect two wind turbines in west Ames that would provide electricity by converting water to hydrogen.

But the Ames plant will go beyond the standard wind turbines because of its ability to store energy using underground hydrogen fuel cells as "batteries," Barton said. The hydrogen could then be reconverted into electricity on demand.

With the go-ahead from the city, the plant could be up and running within 18 months or less, he said.

ENERGY please see page A6

INSIDE: Angry crowd of homeowners confronts council over sidewalks.

Page A6

Energy: Federal funding likely

Continued from page A1

6/23/04 Paul Kendall

Major funding for the project would likely come from the U.S. Department of Energy, which is working on a White House mandated Hydrogen Fuel Initiative to develop the technology needed to find a practical and inexpensive way to convert water into hydrogen fuel.

Barton gave no cost estimate for the proposed Ames project, but said that each of the three entities would play a part in its creation.

ISU will be asked to provide land for the project, possibly one of the university farm sites north of Lincoln Way on County Line Road.

The city would acquire all needed permits and allow connection to the intercity power grid, according to the proposal.

Because each wind turbine could produce as much as $100,000 worth of electricity a year, it is conceivable that Ames could someday have the option to sell part of the energy to other municipalities, Barton said.

The energy plant would be developed and operated by the Ames Lab, which would use the hydrogen produced to continue its research, particularly in a search for a hydrogen hybrid metal.

The Ames Lab is a Department of Energy laboratory operated by ISU on the Ames campus.

Its roots go back to the 1940s, when Ames produced more than 2 million pounds of uranium for the Manhattan Project.

Staff writer Beth Anderson
can be reached at 232-2161, ext. 351, or at banderson@amestrib.com

(1)

BP Gas and power - Renewables & Hydrogen
Renewables & **Hydrogen** products and services - **BP** ... **BP** Gas and power Products and Services Renewables & **Hydrogen** ... ensure **BP** is ready to offer **hydrogen** to ...
bp.com/sectiongenericarticle.do?categoryId=3050016&contentId=3050076 - 36k - Cached

BP Global - Press - Introducing hydrogen power
BP's plan to generate electricity from **hydrogen** and capture carbon dioxide could ... electricity using **hydrogen** manufactured from natural gas to create " ...
www.**bp.com**/genericarticle.do?categoryId=97&contentId=7006978 - 44k - Cached

Ford Motor Company - Press Release - FORD AND BP OPEN FIRST HYDROGEN ...
With **BP** providing **hydrogen** fuel, this event will provide a chance to see ... fuels" said Maria Curry-Nkansah, **BP's hydrogen** business development manager. ...
media.ford.com/newsroom/release_display.cfm?release=24585 - 19k - Cached

BP's only UK hydrogen station demolished - AutoblogGreen
BP's only UK **hydrogen** station demolished. Posted Jun 11th 2007 8:16PM ... For the past three years, **BP** has had a **hydrogen** filling station at Hurnchurch in ...
autobloggreen.com/2007/06/11/bps-only-uk-**hydrogen**-station-demolished - 61k - Cached

People's Daily Online -- China's first hydrogen refueling station goes ...
A website by the People's Daily newspaper; China, business, world, science, ... said Bill Fitzharris, general manager of **BP hydrogen** transport technology. ...
english.people.com.cn/200611/09/eng20061109_319883.html - 28k - Cached

Singapore Environment Institute
... world's largest energy company, **BP** sees **hydrogen** as offering the potential to ... this position, he leads the **BP hydrogen** programme, directs the existing project ...
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California Hydrogen
... announcement, **BP** had already announced plans for two such **hydrogen** power ... near **BP's** current oil-refining operations that heavily use **hydrogen** to produce ...
www.**cleanfleetreport.com**/vault/carson.htm - 11k - Cached

Ford and BP Open Hydrogen Station in Taylor, Another Milestone in ...
With **BP** providing **hydrogen** fuel, this event will provide a chance to see ... fuels," said Maria Curry-Nkansah, **BP's hydrogen** business development manager. ...
prnewswire.com/cgi-bin/stories.pl?ACCT=104&STORY=/www/story ... &EDATE= - 9k - Cached

Green Car Congress: BP and Rio Tinto Form JV for Hydrogen-Fueled Power ...
Online news, ... **BP** and Rio Tinto have formed a new jointly-owned company, **Hydrogen** ... **BP's** previously announced **hydrogen**-fueled power projects in ...
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Media.Ford.com FORD & BP TO BUILD HYDROGEN FLEETS & FUELING STATIONS ...
OFFICIAL NEWS, PHOTOS, VIDEOS, MEDIA KITS, EXECUTIVE BIO&146;S, PRESS ... to place up to 30 **hydrogen**-powered vehicles, and **BP** plans to build a network of ...
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Two oil giants plunge into the **wind** business - The Boston Globe
... some of the biggest players in **wind** power in the United States, accelerating a ... five generators of **wind** power, while **BP's** Alternative Energy group -- launched ...
boston.com/news/.../03/02/two_oil_giants_plunge_into_the_wind_business - 40k

Clipper Windpower Completes Sales Contract With **BP** For Delivery of 300 ...
... or 300 MW, of Clipper's 2.5 MW Liberty **wind** turbines to **BP** for delivery in 2009. ... In the United States, **BP's wind** portfolio includes the opportunity to develop ...
prweb.com/releases/2007/9/prweb556233.htm - 48k - Cached

BP Alternative Energy Acquires **Wind** Energy Co.
... 2005 to bring together **BP's** low-carbon electricity businesses. ... a small **wind** farm on a small acreage that gets sweeping **winds** year around in SW Indiana? ...
www.**renewableenergyaccess.com**/rea/news/story?id=47040&src=rss - 36k - Cached

ALTERNATIVE ENERGY BLOG - Solar-Energy-**Wind**-Power.com: $4b Investment ...
... strong opinions on alternative energy resources including **wind** power, solar energy, wave energy, geothermal & other ... **BP** is making its first major investment ...
alt-e.blogspot.com/2006/07/4b-investment-in-wind-power-by-bp.html - 38k - Cached

Clipper Windpower Press Release
... COMPLETES SALES CONTRACT WITH **BP** FOR DELIVERY OF 300 MW OF **WIND** TURBINES IN 2009 ... In the United States, **BP's wind** portfolio includes the opportunity to develop ...
www.**clipperwind.com**/pr_092607.html - 10k - Cached

BP Breaks Ground On First **Wind** Project in Texas
BP broke ground today on its first **wind** project in Texas. ... **BP** believes that sustainable energy alternatives and the development of the **wind** ...
www.**renewableenergyaccess.com**/rea/news/story?id=49928&src=rss - 38k - Cached

Rocky Mountain News - Denver and Colorado's reliable source for ...
BP's foray into the local **wind** industry came about recently when it bought ... **BP's wind** energy investment here is on top of its continued focus to increase ...
rockymountainnews.com/drmn/energy/article/... - 59k - Cached

North American Windpower: Content / Projects & Contracts / **BP** Plans To ...
BP Plans To Begin Building Five **Wind** Farms In 2007 ... a **wind** project developer under **BP** PLC, has announced that it expects to begin ...
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... International is the worldwide information magazine for the wind energy industry. ... first application at scale of Clipper's new C-96 wind turbine technology for BP. ...
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ENN: BP Breaks Ground On First Wind Project in Texas
... new Texas wind power facility will see 24 2.5 megawatt wind turbine generators, ... BP believes that sustainable energy alternatives and the development of the wind ...
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BP p.l.c. - Information & Fact Sheet - Hoover's
BP is also BO (Big Oil). It is the world's second largest integrated oil concern, behind Exxon Mobil. The company, which was formed in 1998 from the merger of British...
www.hoovers.com/bp/--ID__56872--/free-co-factsheet.xhtml

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BP Breaks Ground on First Wind Project in Texas " Earth 911
Houston, TX — BP broke ground today on its first wind project in Texas. ... BP believes that sustainable energy alternatives and the development of the wind ...
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energyme.com :: BP wind projects for 2007
Your single source for ... BP's US wind portfolio includes the opportunity to develop ... the year, BP acquired two US wind development companies ...
www.energyme.com/energy/2007/20070002S.htm - 19k - Cached

Yankton Press & Dakotan: Story
BP brings capital and expertise to Clipper's effort at developing wind ... 200MW in 2008 which it will use on other projects in BP's global wind business. ...
www.yankton.net/stories/080906/community_20060809038.shtml - 27k - Cached

BP Alternative Energy Buys US Wind Company
... will allow BP to accelerate its plans to develop a leading wind power business in North America. ... BP Alternative Energy announced it had reached ...
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Wind Energy
Harnessing the power of wind... (Skandia) It is the ultimate renewable resource. ... Sharp, Kyocera, and BP are also large manufacturers of solar modules, but this ...
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BP and Rio Tinto unite to develop clean energy projects

■ **VENTURE:** Company initially will look into hydrogen-fueled power.

The Associated Press

LONDON — Oil producer BP and miner Rio Tinto will be working together to develop clean power projects around the world, the companies said Thursday.

The joint venture will initially focus on hydrogen-fueled power generation, using fossil fuels and carbon capture and storage technology to produce new large-scale supplies of clean electricity.

"Projects such as these have the potential to help deliver the carbon emission reductions which companies and countries around the world are now seeking," said BP Chief Executive Tony Hayward.

BP said that previously announced hydrogen-fueled power projects in Peterhead, Scotland, and Carson, Calif., will become part of Hydrogen Energy. Rio Tinto will make a cash payment to BP of about $32 million, subject to post-completion adjustments.

The new company will be based in Weybridge in southeast England and will initially have a staff of 75 transferred from the parent companies.

Lewis Gillies, formerly head of BP's hydrogen power business, will be chief executive of Hydrogen Energy and Peter Cunningham, formerly head of business evaluation for Rio Tinto, will become chief financial officer.

Paul D. Kendall

from page 20

smission Facilities for Re-
enerators," the new catego-
e defined as "high-voltage
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is aiming for FERC to ap-
concept of the proposal
le feedback if there are any
till. According to Perez,
time limit for FERC to re-
proposal, but he hopes to
ponse by April. If they do
approval, CAISO would
to acquire the stakehold-
which would most likely
o three months, and then
le the proposal with FERC.
on President Bush's recent
he Union address, which
generating more renew-
y, Perez believes FERC will
e proposal.

"If you've been following all the action in Washington, D.C., the action has been renewables, renewables and renewables," he says. "Here we're coming with a proposition that will facilitate renewable development. If I were a betting man, I would bet they would pass it."

– Shelley Paventy

Paul D. Kendall

Wind Power Increases Worldwide

NAW 02-07

Reports from the American Wind Energy Association (AWEA), the European Wind Energy Association (EWEA) and the Global Wind Energy Council (GWEC) show solid growth in wind power markets around the world.

In terms of new installed capacity in 2006, the U.S. continued to lead with 2,454 MW, followed by Germany (2,233 MW), India (1,840 MW), Spain (1,587 MW), China (1,347 MW) and France (810 MW), according to GWEC's annual figures for 2006.

AWEA reported in its recent market forecast that wind power generating capacity in the U.S. increased 27% to 11,603 MW in 2006 and is expected to increase an additional 26% in 2007.

"iPods, flat screen televisions and other highly sought technologies are creating a demand for electricity that is beginning to eclipse our current supply," says Randall Swisher, executive director of AWEA. "Wind is a proven, cost-effective source of energy that also alleviates global warming and enhances our nation's energy security."

The forecast indicates the U.S. wind energy industry invested approximately $4 billion in new installations, making wind energy the second largest source of new power generation in the country, behind natural gas.

AWEA's industry outlook also found that:

- Texas accounted for nearly a third of the new wind power installed in 2006,
- new utility-scale turbines were installed in a total of 29 states across the country and
- the top five states in new installations were Texas (774 MW), Washington (428 MW), California (212 MW), New York (185 MW) and Minnesota (150 MW).

GWEC's annual figures for 2006 reveal that 15,197 MW of wind energy was installed in 2006 around the world, bringing the total installed wind energy capacity for more than 70 countries to 74,223 MW – up from 59,091 MW in 2005. The countries with the highest total installed capacity are Germany (20,621 MW), Spain (11,615 MW), the U.S. (11,603 MW), India (6,270 MW) and Denmark (3,136). Thirteen countries around the world can now be counted among those with over 1,000 MW of wind capacity, with France and Canada reaching this threshold in 2006.

According to EWEA, 7,588 MW of wind power capacity, worth approximately 9 billion euros, was installed last year in the European Union (EU) – an increase of 23% compared to 2005. The cumulative wind power capacity operating in the EU increased by 19% and now exceeds 48,000 MW.

AAER To Open Plant

Bromont, Quebec-based wind turbine manufacturer AAER Inc. has signed a ten-year lease agreement, with an option for an additional five years, with Olymbec Inc., the owner of buildings that housed the former Hyundai plant in Bromont.

Under the terms of the agreement, AAER has leased 111,141 square feet to be used for the assem-

ACTS

ission, the RPS requires each investor-owned utility to increase its procurement of eligible renewable generating resources by 1% of load per year to achieve a 20% goal. Buena Vista will provide over 38 MW of wind power to the state's electricity customers.

"We are very glad to partner with PG&E in the first and important repowering in the Altamont area," says Mike Garland, head of Babcock & Brown's North America Infrastructure Group, the developer of the project.

Ontario Project Started

Acciona Wind Energy Canada Inc., a renewable energy project developer and affiliate of Acciona S.A., and Suncor Energy Products Inc., a wholly owned subsidiary of Suncor Energy Inc., have started construction on a 76 MW wind farm located near Ripley, Ontario.

Foundations for the 38 2 MW Enercon wind turbines are now being poured. Pending weather conditions, construction will take a brief break during the winter months and is expected to be complete this summer, with the project commissioning scheduled for late 2007.

The wind farm is located in Huron-Kinloss township, approximately 220 kilometers west of Toronto. The project is expected to have the capacity to power 24,000 homes and offset 66,000 tons of carbon dioxide per year.

In addition, Suncor and Acciona will submit an application for funding from the Canadian government's recently announced ecoEnergy Renewable Power Initiative, which supports wind power development in Canada.

MARCh-07

NAW 02-07

BP Plans Five Wind Farms

BP Alternative Energy North America Inc., a wind project developer under BP PLC, has announced that it expects to begin construction on five wind power projects in the U.S. in 2007.

According to BP Alternative Energy, the projects are expected to deliver a combined capacity of approximately 550 MW. Construction is currently underway on the 300 MW Cedar Creek project, a development venture between BP Alternative Energy and Babcock & Brown, in Weld County, Colo. The 274 turbines that the project calls for will be erected on a 32,000-acre site. According to Governor Bill Ritter, D-Colo., who supports the wind farm, it will create up to 250 jobs and has the capacity to power 120,000 homes.

Paul O Kendall

NOTE: 250 homes p/MW × 300 MW 75,000 Homes @ 29% Wind Flow

The remaining projects include a 65 MW wind farm in North Dakota, a 60 MW joint project with Clipper Windpower in central Texas, a 100 MW project in western Texas, and the Yaponcha wind power project in California. The Yaponcha project consists of repowering an existing wind energy facility in San Gorgonio Pass – the company expects the facility to have a capacity of 20 MW.

"Our 2007 build program surpasses our target and does so a year ahead of schedule," says Robert Lukefahr, president of BP Alternative Energy. "It is a testament to the caliber of people working in our business and the opportunities in the U.S. wind sector."

BP Alternative Energy adds that it plans to deploy 150 MW of Clipper Liberty wind turbines in the projects as part of the supply and joint development agreement it entered into in 2006 with Clipper Windpower.

BP just built Hydrogen Refueling Station in Beijing, China.

NBP, TransAlta Enter PPA

Calgary, Alberta-headquartered TransAlta Corp., a generator of electricity from a variety of sources, including renewable energy, has entered into a 25-year power purchase agreement with New Brunswick Power, a New Brunswick-based power supplier. The agreements represent the province's second power purchase agreement.

Under the terms of the agreement, TransAlta will provide 75 MW of wind power to New Brunswick Power. TransAlta will construct, own and operate a wind power facility in the Kent Hills area of New Brunswick. Natural Forces Technologies Inc., a local Atlantic Canada wind developer, is TransAlta's co-development partner in the project.

The 25-turbine wind farm is subject to regulatory and environmental approvals, and is expected to begin commercial operation by the end of 2008, the companies say. Once complete, it will provide a capacity of 220,000 MWh per year, which is enough electricity to meet the needs of approximately 13,000 homes. The

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1 Energy Co., a Des
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Co., is seeking ap-
Iowa Utilities Board
40 MW of wind en-
s power supply.

"In addition to the environmental benefit of adding new wind energy production in Iowa, customers of MidAmerican Energy will continue to benefit from electric rate stability," says Greg Abel, president of MidAmerican Energy Holdings. "The last electric rate increase MidAmerican Energy customers experienced was in 1995, and we propose adding the new wind energy while maintaining electric rate stability until 20.4, which is nearly 20 years of electric rate stability for MidAmerican Energy customers."

In addition, the company has announced plans to erect a wind turbine for renewable energy generation at the Iowa State Fairgrounds. The Iowa State Fair wind turbine will be built in part due to the voluntary customer donations to MidAmerican Energy's Renewable Advantage program. Since its inception in 2004, more than $150,000 has been donated to the program. MidAmerican Energy will fund the remaining $743,000 required to erect the wind turbine and make a $4,000 annual payment for the easement for the wind turbine site, the company says.

Construction of the turbine is scheduled to begin this spring and be completed in time for this year's fair, MidAmerican Energy adds.

JUNE - 07

BP Orders Wind Turbines

Vestas Americas A/S of Portland, Ore., has received an order from BP Alternative Energy North America Inc. for 50 V90-3.0 MW wind turbines to accelerate the growth of BP's U.S. wind portfolio.

According to the companies, delivery of the turbines will commence in the fourth quarter of this year. Vestas will supply and commission the 50 wind turbines as well as maintain and service them for five years.

"The V90-3.0 MW turbine is an important part of our growth in the North American marketplace, and we are pleased that BP has included this turbine type in its wind portfolio," says Jens Soby, Vestas Americas' president.

THERE IS NO SUCH THING AS WATER! - ONLY VARIOUS HYDROGEN COMPOUNDS!

PAUL D KENDALL

PAUL D. KENDALL
222-7882 4-12-07
TO: A CIA REVIEW

8. TECHNOLOGY DEVELOPMENT

*"...the discovery with which we are dealing involves forces of nature too dangerous to fit into any of our usual concepts." (The Congressional Record of 1875, concerning the discovery of gasoline).**

HYDROGEN?

* Quoted by Anthony M. Moos in *Fuel Cells,* Vol. II, ed. G. J. Young, (New York: Reinhold Publishing Corporation, 1963).

THESE FIGURES ARE NOT VERIFIED!

NEED VALIDITY!

Paul D. Kendall

11-16-07 ENERGY OUTLAYS

ENERGY	Annual Nat Avg	Annual AK Avg	X X SFHOM Annual SFHOM Avg	Monthly SFHOM	Annual X 1,000 homes = cu ft. nat gas
Natural Gas		175,000 cu ft.	150,000 cu. ft.	12,500 cu. ft.	150,000,000 cu. ft.
1 cu.ft.=1,031 btu		180,425,000 btu	154,650,000 btu	12,887,500 btu	154,650,000,000 btu
		175 Mcf	150 Mcf	12.5 Mcf	150. MMcf
*Electricity		8,500 Kwh	7,200 Kwh	600 Kwh	7,200,000 Kwh
1 kwh=3,412 btu		29,002,000 btu	24,566,400 btu	2,047,200 Btu	24,566,400,000 btu
		28,130 cu. ft.	23,828 cu. ft.	1,986 cu. ft.	23,828,000 cu.ft.
		28.1 Mcf	23.828 Mcf	1.986 Mcf	23.828 MMcf
Gasoliine	468 gal.	1,500 Gal	2 3/4 Gal [illegible] 1,000 Gal	250 Gal.	1,000,000 Gal
1 Gal=124,000 btu		186,000,000 btu	124,000,000 btu	31,000,000. btu	124,000,000,000 btu
=1203 cu ft		180,407. cu. ft.	120,272. cu. ft.	30,068. cu. ft.	120,272,000 cu. ft.
		180.4 Mcf	120.3 Mcf	30.1 Mcf	120.3 MMcf
$ p/cu ft Water → 120.30 /Cost					
Sewage					
Property Taxes					

----

* check on gas amount to produce – power loss in transmission $1110

$1,470,000 p/YR

Bill Noble 2006 – [illegible] – 11%
LNG 36.7%
N. Slope 19.6%
Power 21.8%
96%

@ [illegible]

Paul D. Kendall

3/5/08

Old Booklet

HISTORY AND DEVELOPMENT OF STEAM BOILERS

TALK BY S.T. MACKENZIE

SALES MANAGER

THE BABCOCK & WILCOX COMPANY

BOILER DIVISION

TO

NORTH CAROLINA SOCIETY OF ENGINEERS

WILMINGTON, N.C., AUGUST 5, 1954

BULLETIN [illegible]

History and Development of Steam Boilers

by S.T. Mackenzie

Each state in the union has its own particular claim to fame, but when I think of "North Carolina" there always comes into my mind a picture of good, sound progress symbolizing a spirit that is cognizant of tradition, but not hopelessly chained to it; a spirit dedicated to advancement but not always seeking the new merely for the sake of change.

There are many things which make North Carolina a great state. Its people, its resources, its enterprises. Important among the elements that have contributed to the rapid growth of your state is the presence of many engineers and their organization into societies such as you have here. Progress doesn't just happen. It takes enterprise. It takes thought. It takes courage. Most of all, it takes engineers. Without engineers to translate dreams into practical, working, economical reality, we would be a poorer, weaker nation.

We cannot single out any branch of engineering as being a greater contributor than any other to our mutual progress. We are all too interdependent, need each other too much to draw any fine distinctions.

No place is this better illustrated than in the subject which I am discussing today: "The History & Development of Steam Boilers". Perhaps I should have called it: "More Steam - Less Muscle".

Offhand, nothing sounds quite so commonplace as steam boilers. They've been around for years. It might be more exciting to talk about supersonic jets, gas turbines, moon rockets, or what have you.

But lets put this steam boiler in perspective. Why was it important? Why is it important today? Why will it be important in the future? I think we can see the answers to these questions quite clearly if we just go back to our fundamentals for a moment.

When did men first begin to develop the steam boiler in earnest? Why, when they really needed energy on a scale greater than that which could be supplied by human and animal muscles. Of course, as long ago as 150 B.C., Hero of Alexandria suggested this boiler and reaction turbine, but the society of the times was not ready for it. It was not until nearly 18 centuries later, in 1629 that Branca made this drawing of an impulse turbine. By this time, however, many conditions existed which sparked the rapid development of this new source of energy: Mining for ores and minerals had expanded to a really great scale and large quantities of fuel were needed for smelting. In addition, considerable fuel was needed for space heating and cooking. Industrial and military growth, especially in England, also demanded ever greater amounts of fuel. By the middle of the 1600's forests were being rapidly denuded and it became increasingly necessary to find some other basic source of energy. Thus despite the fact that 300 years ago people were executed in England for burning coal because it produced highly noxious and dangerous fumes, the dynamics of historical growth made it essential to remove these restrictions, and coal mining began to increase.

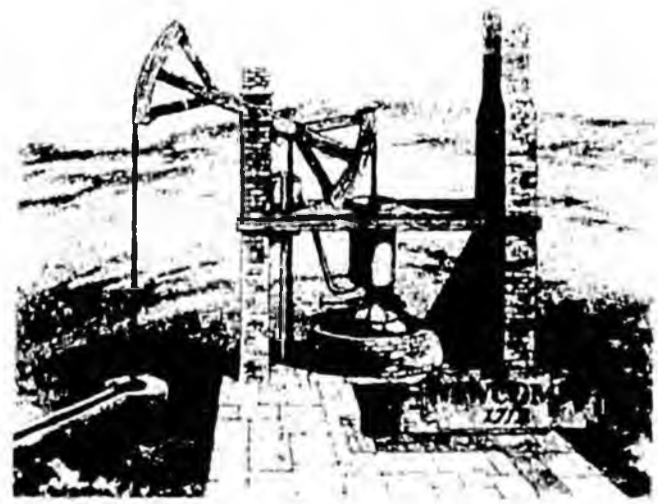
As coal began to be mined on a large scale, mines became deeper and deeper, and were often flooded with water. The English, in particular, were faced with a very serious curtailment of their growing industrial, military and political might if they could not find some economical way to pump the water out of their coal mines. The importance that was attached to this problem can be seen from the great number of men who were working on it and by the many, many patents that were issued on machines to pump water by the use of "the expansive power of steam."

This mutual dependence of fuel and machine is not always correctly explained. It is true that the development of machinery created a demand for fuel, but it is even more significant that the need for more fuel created a demand for machinery. The early machines used wood and charcoal as fuel. Many years elapsed before the application of machine power to fuel procurement could bring production of fossil fuels up to a high enough point to displace wood.

Incidentally, those early developers were fully aware of the nature of the energy they were using. Their machines were invariably referred to as "fire engines", since it was the energy of the fire that was being harnessed and transmitted through the medium of steam.

SAVERY

Savery's steam engine of 1698 used the vacuum -- achieved by alternately forming steam in a cylinder and then chilling it -- to pump water from mines. His might be considered the first practical engine, and it was actually used in various locations.



NEWCOMEN

The first important development for securing useable energy through the medium of steam, however, originated with Thomas Newcomen, an iron monger living in Dartmouth, England. His first engine was based upon the concept that if steam were admitted to a cylinder in which was fitted a piston, and then a jet of water were admitted and the steam condensed, the pressure of the atmosphere on top of the piston would force the piston down the cylinder and thereby produce power which could be utilized for the then most important purpose of pumping water from coal mines.

HAYCOCK
BOILER
1720

Newcomen produced what is probably the first commercial steam engine and in 1712 had one operating in a mine at Cornwall in England. Note that the boiler for this engine - referred to as the Haycock type because of its shape -- was really a plain copper brewers kettle. Pressure was that of the atmosphere. The success of Newcomen was due to his conception of a device that would use steam at or below atmospheric pressure, thus accommodating his needs to the construction abilities and materials of the day.

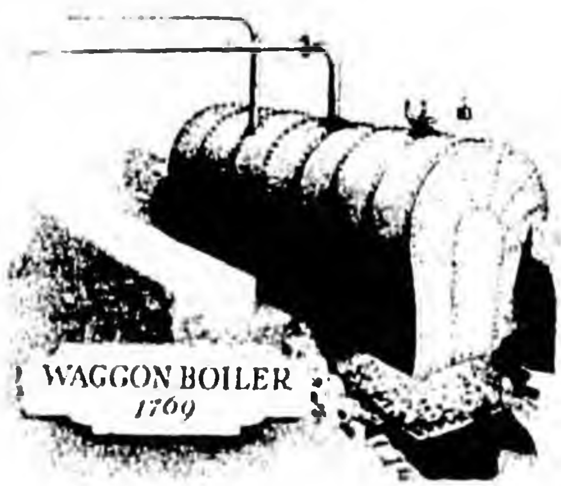
WATT

The next significant development in the steam engine came through the efforts of Watt, whose genius and enterprise really put the steam engine on the market in a large way. Watt's partnership with Bolton, who was an excellent business man with capital and machine and foundry facilities, produced a combination that brought about a very rapid development in the entire field of steam power.

Watt began his experiments with the steam engine in 1760, but commercial realization came about 1790 and this is regarded as the beginning of the industrial revolution -- only 165 years ago.

Watt's principal concept was that if the steam could be condensed in a separate shell distinct from the cylinder itself, the heat lost by the cooling of the cylinder in Newcomen's engine would be saved and that the amount of power could be increased to whatever extent pressure increase was permitted by improvements in boiler design. The condenser separate from the cylinder itself produced a saving of approximately 1/3 in the coal required for a given duty.

Among Watt's many contributions to engine improvement, perhaps the most important was his device to translate the reciprocating motion into a rotative motion. This development of the so-called rotative engine permitted its introduction into mills and factories where belts and pulleys could transmit the power to rotating machinery. Thus began the process of substituting energy for man's muscles -- a process still with us, and perhaps still in its infancy.



Watt's records show that he fully realized the advantage of higher pressure steam but he never built a boiler for these higher pressures and expended all of his efforts on the engine. He used the Waggon type boiler which produced large amounts of steam at about 5 pounds pressure.

Watt studied the scientific end of his problem probably more than any one who preceded him and developed tables showing the expansion of steam and changes in volume at various pressures. Incidentally, as we will discuss later, the investigation of steam properties is today an important necessity.

TREVITHICK

The next outstanding figure was Richard Trevithick, who as a boy of eight went to work in one of his father's mines in an English mining district. There he received as much engineering training as was available in those days, since his father was manager of several mines and thus Richard was permitted to travel from engine house to engine house and observe the pumping engines, principally of Newcomen design.

TREVITHICK 1804

Trevithick realized the problem was still largely one of manufacturing the boiler. Whereas copper was the only material heretofore available, hammered wrought-iron plates could now be used although the maximum length was 2 ft. Rolled-iron plates became available in about 5/16" thickness in 1795.

In 1800 Trevithick made an engine for 65 lb pressure, having a 25" cylinder and a 10 ft. stroke. This same high pressure made possible the successful construction of a high pressure engine and boiler mounted together. This boiler was built in 1804 and had a cast iron cylindrical shell with the rear end dished.

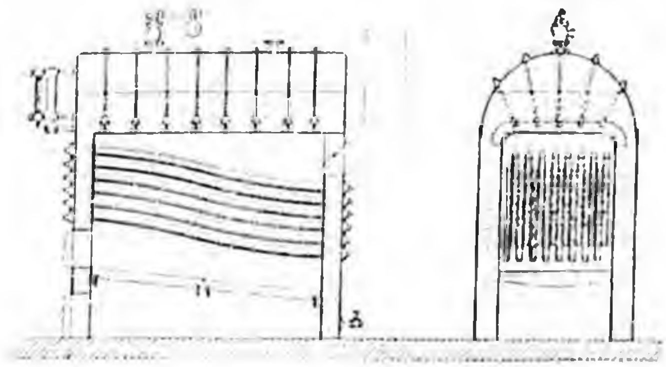
CORNISH BOILER 1812

CORNISH BOILER

As the demand increased for larger and larger amounts of power, it was necessary to build larger and larger boilers, or put up with the inconvenience of a multiplicity of small units. Here is a typical Cornish boiler. Later developments saw the flue broken up by many gas tubes to increase heating surface as much as possible. This was essentially the design in widespread use up to about 1870. However, fire-tube boilers were limited in capacity and pressure. Also, because all of the steam was concentrated in one big shell, parts of which were exposed to radiant heat, they were subject to disastrous explosions.

WATER TUBE BOILERS

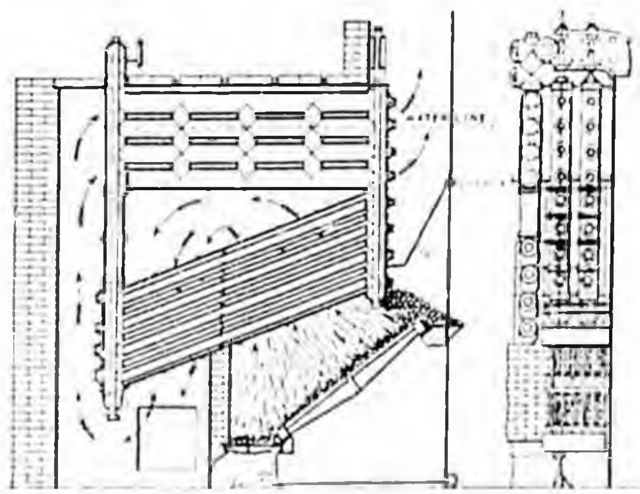
This question of boiler capacity and safety was of basic importance, and it is no exaggeration to say that for a time failure to develop adequate boilers threatened to halt industrial progress.



However, man is an inventive creature, and the moment a challenge arises, he sets to work with might and main to lick it.

The way to overcome the deficiencies of the fire tube boiler was to use a water tube boiler.

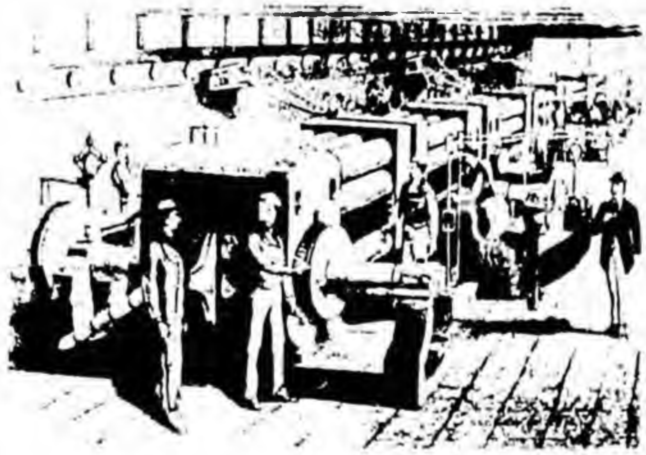
In 1856 a water tube boiler was designed and patented by Stephen Wilcox, although it was not built until several years later. The drawing shows a sinuous tube at an incline rather than a straight tube.



In 1867 Stephen Wilcox patented a straight tube boiler with tubes at 15 degree slope and arranged with handholes in the header so that there was access to the tubes for cleaning. The horizontal cast iron tubes at the top of the unit served in place of a steam and water drum. The vertical rows of inclined steam generating tubes were also of cast iron and were cast en-bloc. Internal tubes or cores were placed within the inclined tubes to aid circulation.

Stephen Wilcox clearly understood the forces involved in natural circulation. With this knowledge, he was able to design safe, economical boilers that could produce the large quantities of steam that an expanding industry needed to run its processes and improved engines.

The greater amounts of steam available from water tube boilers, their safety and increased economy thus gave a great impetus to industrial expansion in the period between 1870 and 1900. These boilers were important elements in the rapid growth of electrical generation for power and lighting.



75 years ago, when Edison, using water tube boilers as his source of steam, harnessed the steam engine to the electric dynamo, he began a whole new era in energy production. At the same time, he opened up new concepts in the field of energy distribution. Two great problems were being solved:

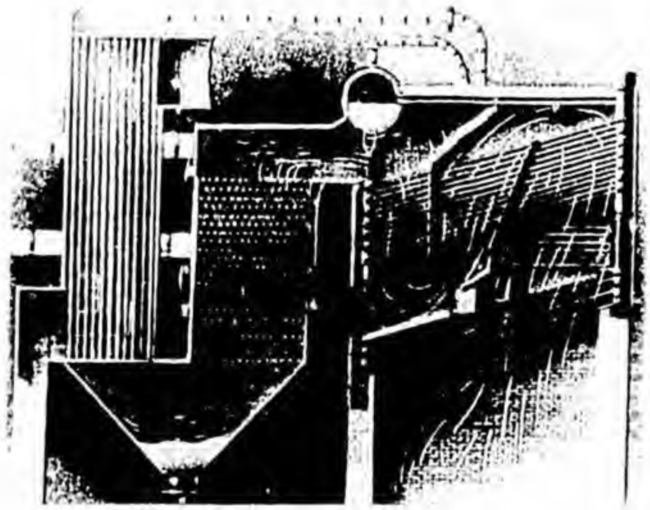
A) How to manufacture useable energy economically

B) How to transport it cheaply and safely over great distances

We are still in the middle of this great engineering advance.

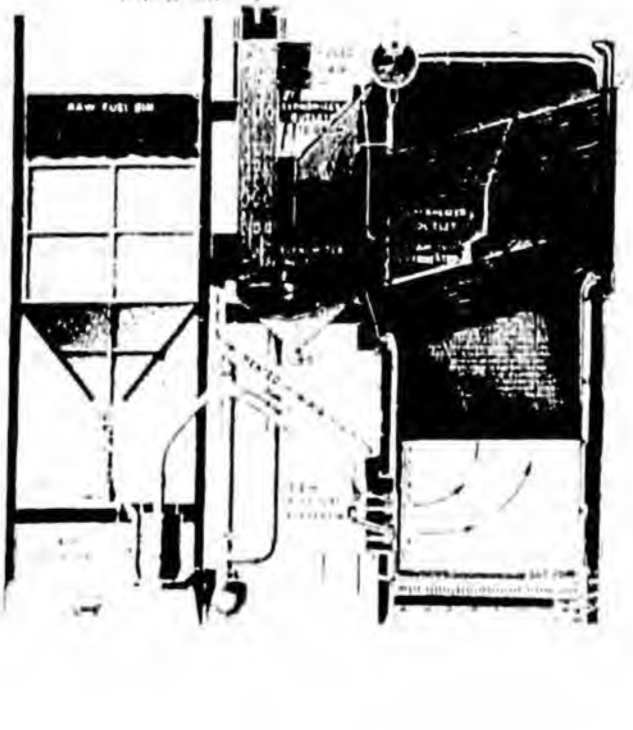
With the development and application of the steam turbine, in the early 1900's, higher steam pressures and temperatures were needed for most economical operation. Superheaters were added to boilers as a means of heating steam above the saturation temperature. To meet the demands for greater steam output, boilers were increased in size, and hand firing gave way to stoker firing.

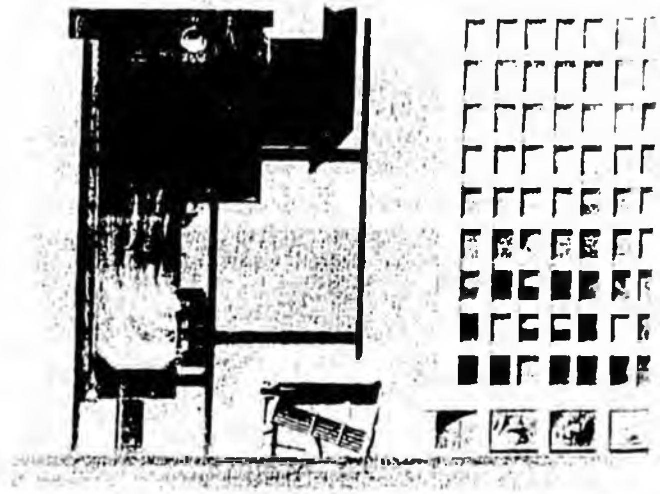
Higher steam pressures and temperatures, together with greater steam outputs, were resulting in higher heat losses up the stack. Part of these losses could be recovered by adding more boiler surface, but it was generally found to be more economical to add an economizer or an air heater, and often both. Feedwater passing through the economizer absorbed considerable heat before entering the steam drum. Preheating the incoming air for combustion greatly improved furnace efficiency. Later, in the 20's many units were equipped with reheaters, to reheat the steam after it had passed part way through the turbines, thus improving turbine efficiency.



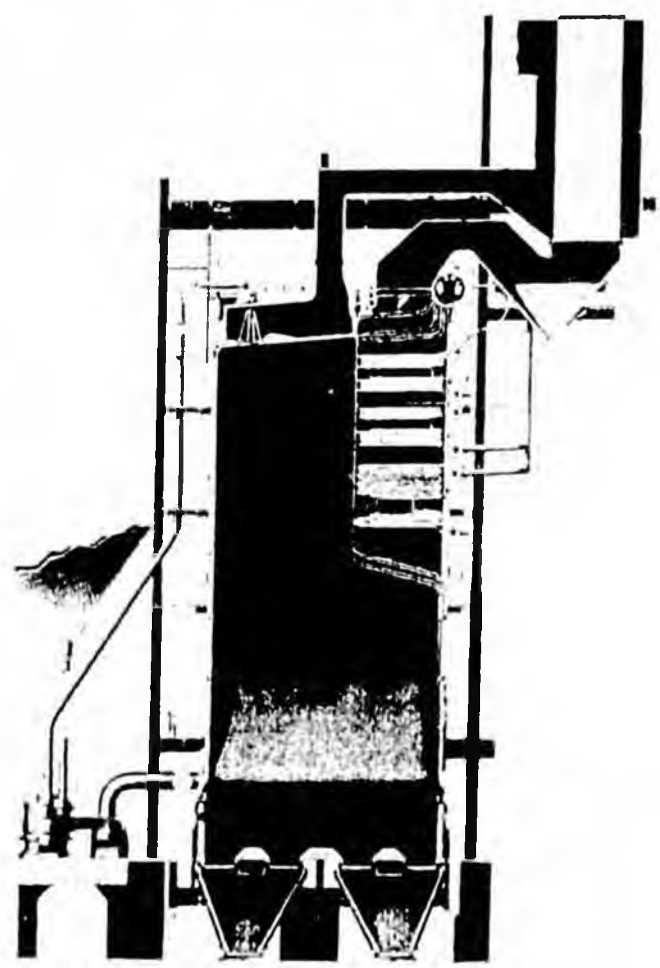
Burning coal in powdered form had long attracted the interest of boiler engineers as a means of simplifying and improving combustion efficiency. Pulverized coal-firing made rapid strides in the 1920's. Not only was efficiency improved, but a wider variety of coals could be used, and steam output was increased without excessive increases in boiler size. Early applications retained brick-lined furnaces. These were often air-cooled in an effort to reduce punishment on the brickwork. But it was evident that new types of furnaces were needed if full advantage were to be obtained from this method of firing.

The need for improved furnace linings led to the development of water-cooled furnaces. Many different stages were passed through in this development, including a combination of part water-cooled and part refractory furnaces; tubes covered with metal or refractory-lined blocks; tubes embedded in plastic refractories, and bare-tubes backed with refractories. An important feature was that the tubes forming the water-cooled surface were an integral part of the boiler system, and the heat they absorbed was fully utilized to make steam.

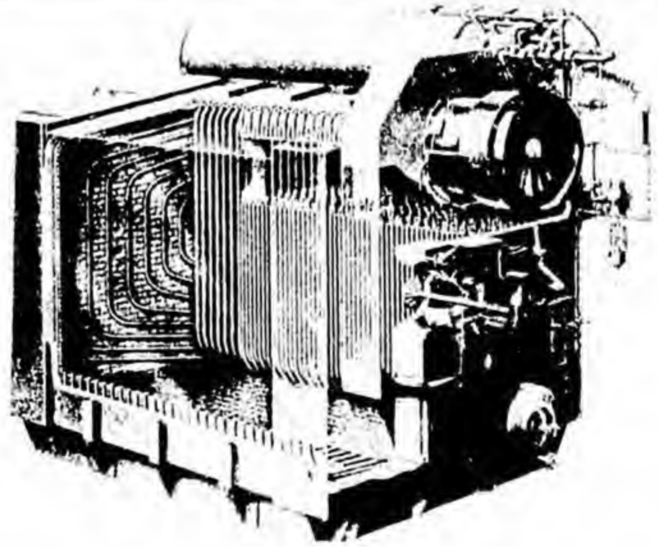




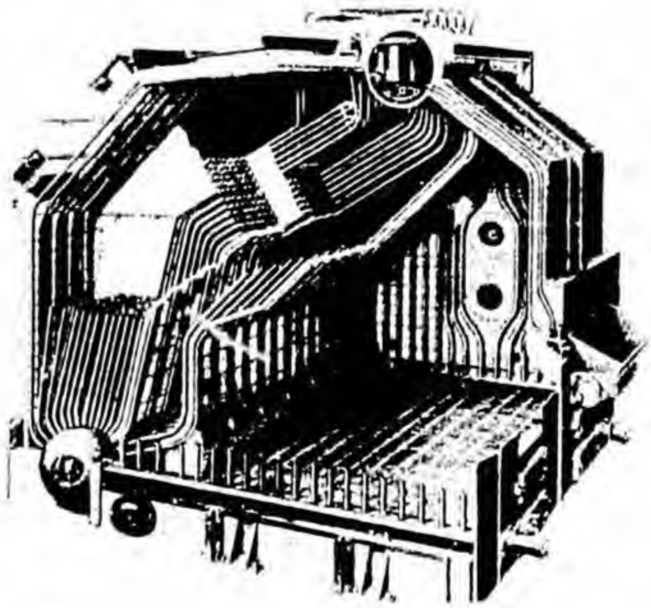
In addition to the steps outlined, progress in steam generation is being furthered by continuous work on such problems as ash and slag control; improved firing methods; metals for higher pressures and temperatures; steam purification; circulation; and many others. Thus, at the mid-point of the 20th Century, the modern central station boiler represents a great advance over the first units used by Edison 75 years ago. Its height often exceeds that of a ten-story building. Its furnace may consume as much as 20 carloads of coal per day -- and its capacity may be over 1,700 000 pounds of water evaporated, per hour. Design pressures extend as high as 2700 psi, and steam temperatures of 1100 F are becoming common.



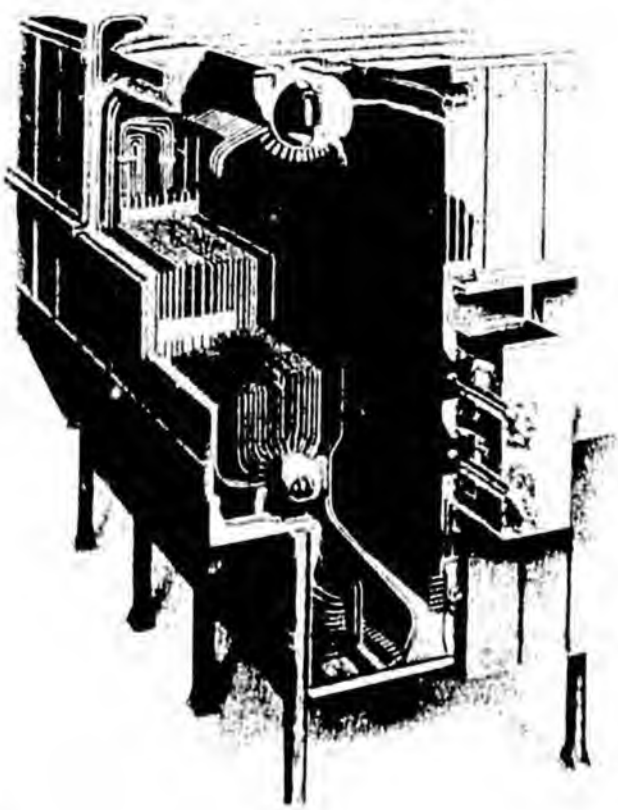
The Radiant Boiler is typical of present day central station designs. It is essentially a large water-cooled furnace with a superheater, economizer, and air heater. Reheaters are often added to improve turbine efficiency. An important feature is the high degree of reliability, so that single-boiler-per-turbine installations, with no standby units or cross-connecting piping, have become standard practice. Boilers are often not taken off the line from one year to the next, except for mandatory annual inspections.



At the other end of the scale is the package unit, used for the heating and steam process needs in many industrial plants, hospitals, and large buildings. It is a fully automatic self-contained unit that is shipped completely assembled requiring a minimum of work in the field to place it in operation.

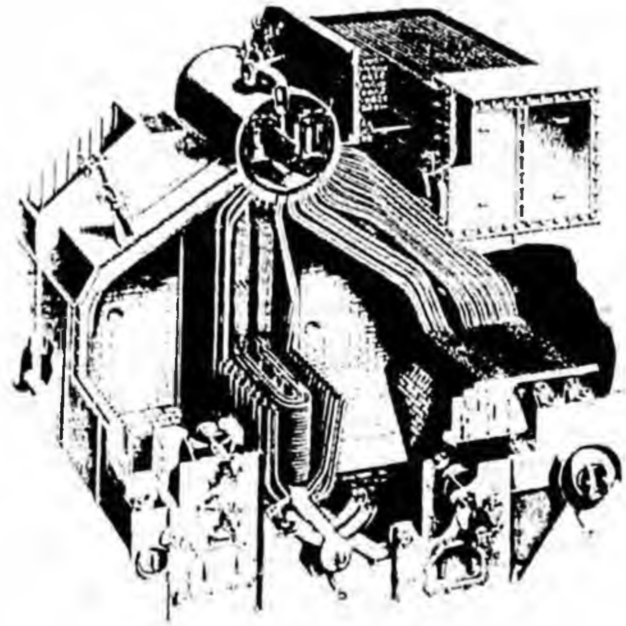


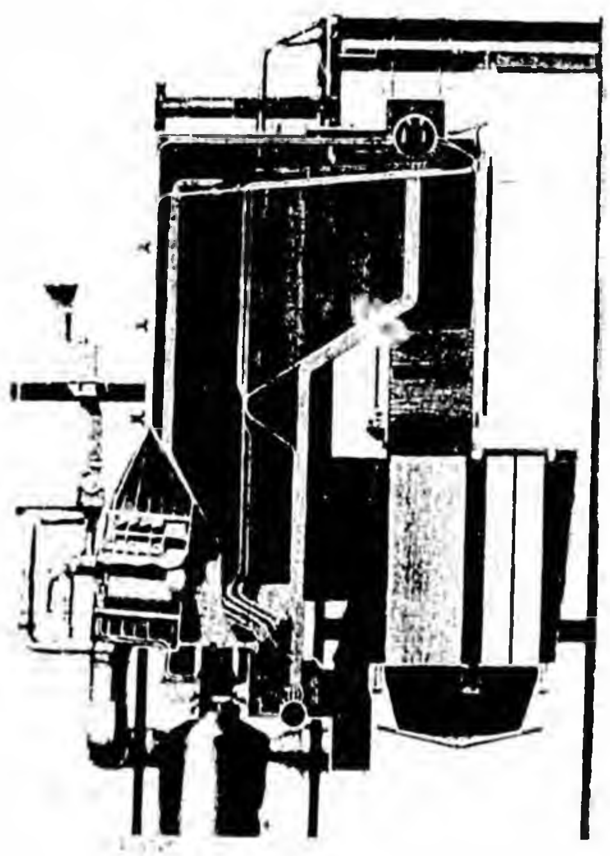
Important in modern boiler practice is the fact that the features of economy and durability developed in large central station units have also been incorporated in smaller boilers for industrial use. Typical of the units which are available for economical steam generation in the moderate-capacity range is this Integral-Furnace Boiler, which is adaptable to steam requirements ranging between 8000 pounds and 50,000 pounds per hour.



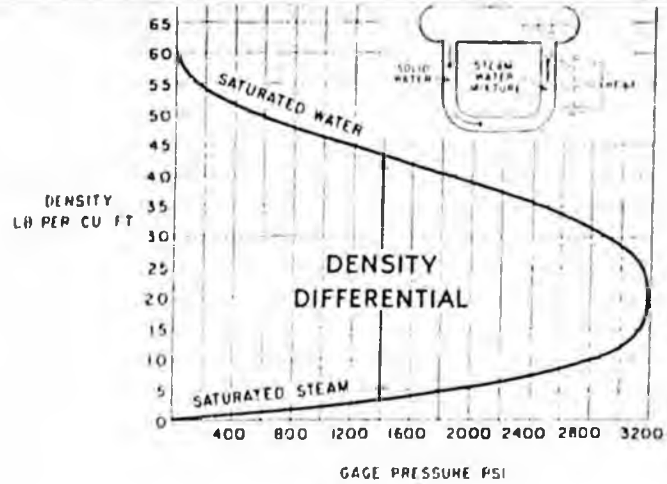
This larger Integral-Furnace Boiler, is used in large industrial plants and many central stations. It is adaptable for steam requirements up to 350,000 pounds per hour, pressures to 1150 psi, and temperatures to 910 F. The hopper bottom design contributes greater furnace cooling area, providing for a self-cleaning furnace and continuous dry-ash removal.

Boilers for Naval and Merchant Marine use call for special designs because of the need for compactness, lightweight, and the high degree of maneuverability required for vessels at sea and in port. The Single-Uptake, Controlled-Superheat Boiler is one of a series of designs contributing to the high degree of economy embodied in American Naval and Merchant vessels.



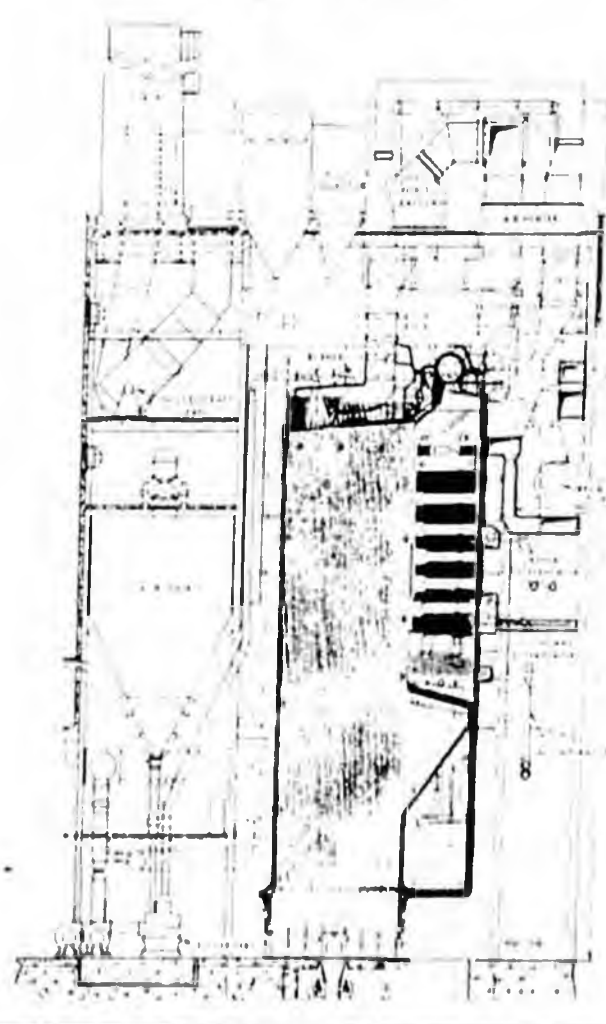


The Cyclone Furnace is typical of the manner in which constant attention to the all important matter of greater economy in steam generation is forever leading to new inventions. Crushed coal, blown spirally at great speed into the Cyclone Furnace, is embedded in a coating of slag, where it burns rapidly in a continuous blast of high-temperature air travelling at 200 mph. The Cyclone Furnace traps 90% of the ash in the form of molten slag, which can be readily drained off, and gases passing up to the stack are relatively free of fly-ash.

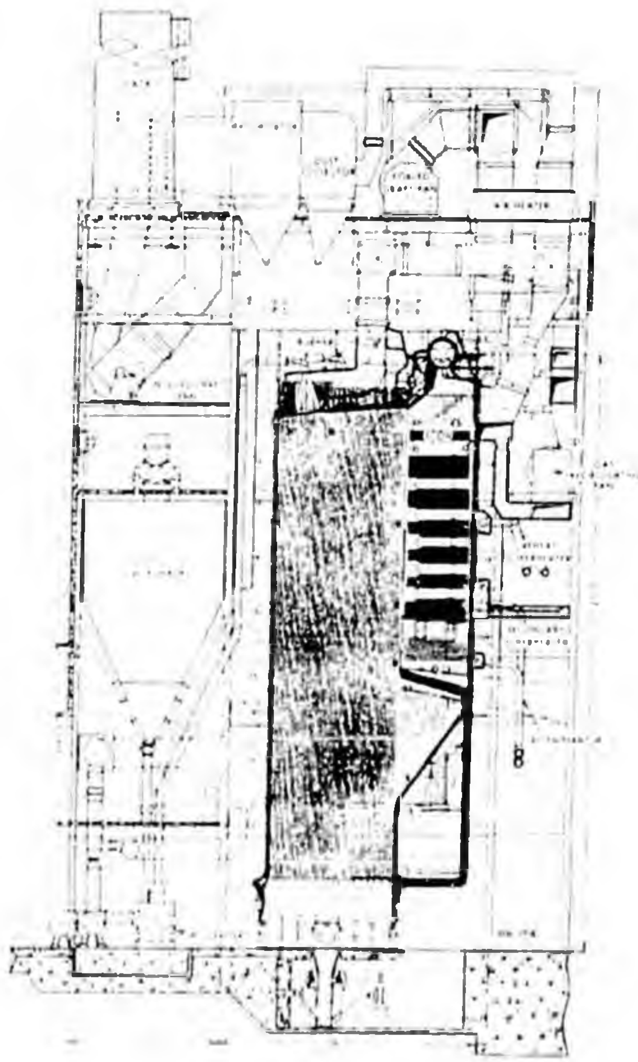


One important feature is common to all these units: They operate with natural circulation. No pumps are needed to force the water through the tubes. The water flows because of the differences in density between water on the one hand, and the steam-water mixture on the other. However, as water and steam pressure goes up, this density differential becomes less and less, until it disappears at the critical pressure of 3206 psi. For a while, this threatened to delay progress toward the use of higher steam pressures. However, in the mid 1930's The B&W Co., developed the Cyclone Steam Separator, which is located inside the Steam Drum. This causes the steam-water mixture to whirl in a cyclone action. Heavy, dense water is directed downward, and the light steam rises. With this device, it was possible to build boilers for natural circulation to pressures as great as 2700 psi.

So here is where we stand today. This great boiler might be taken as a symbol of progress since Stephen Wilcox first developed his water tube boiler only a century ago. It supplies steam at 2000 psi, 1050 F to run a reheat turbine generating 217,000 kilowatts. It burns 80 tons of coal an hour, which is ground in these pulverizers to talcum powder fineness. This coal is blown into a furnace which operates under pressure, another great forward step in recent years. Instead of using two fans - one to push air in, the other to draw gases out, only a forced draft fan is used. This means significant savings in construction costs, fuel costs and contributes to operating simplicity.



The steam is superheated to 1050 F and, after passing through the high pressure turbine, returns to the reheater where its temperature is again raised to 1050 F so it can do its work efficiently in the low pressure turbine. Now I toss off this steam figure of 1050 F very lightly. But did you ever think of the kinds of metals needed to contain steam at this temperature -- which is so high that the pipes carrying it actually glow in the dark? Behind that simple statements stands a whole history of technological development without which power progress would have been seriously curtailed.



This unit has an efficiency of about 90 per cent. In other words, it is taking just about all of the heat out of the fuel that is economically possible.

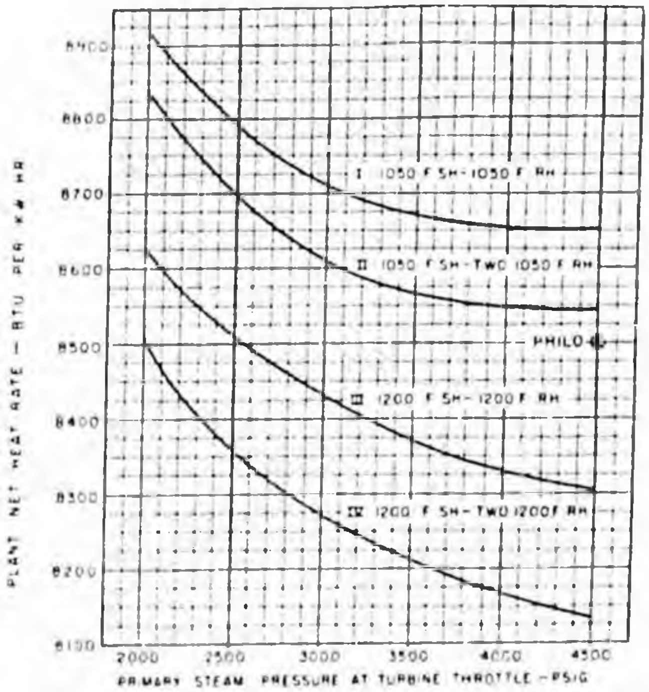
This boiler and its associated turbo-generator produce a kilowatt-hour for about 9000 Btu. Only thirty years ago it took 18,000 Btu to do the same job. Surely this is a great forward step -- one of which we as boiler designers are proud -- but of which each of you as engineers can also be proud, because it is the achievement of the entire profession working with devoted cooperation that has made it possible.

These great energy-machines are a key to the power and well-being of our nation today.

Now, I believe I have shown why steam boilers were important in the past and why they are important today. What of the future?

I would like to touch on two important developments -- one of immediate interest and the other having a longer range significance.

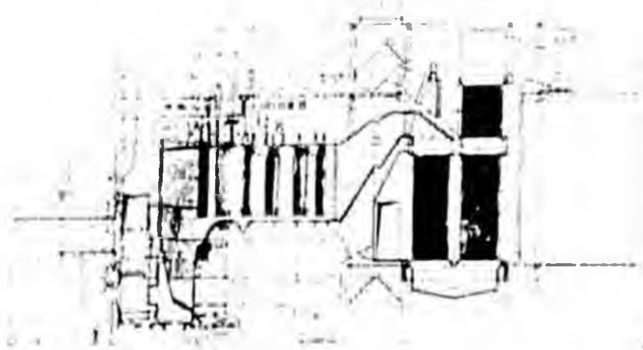
This collection of curves points out rather well the direction in which we must go for further development in conversion of energy from fuel to electricity. It shows plant net heat rates for various combinations of pressures, temperatures and reheat cycles.



EFFECT OF STEAM PRESSURE AND TEMPERATURE
PLANT NET HEAT RATE

Where the top curve intersects 2000 psi is just about where we stand today. As you can see, merely increasing pressure is not going to give as much gain in heat rate. We have to increase both the temperature and the pressure. For example, if we used 4500 psi pressure and 1200 F steam temperature, with two reheats to 1200 F, we would have a heat rate of about 8100 Btu per net kilowatt-hour. However, while we are ready with superheater and reheater alloys for these conditions, the turbine manufacturers are, very understandably, not quite ready for the entire jump. Therefore, for the next step, we are going to 4500 psi, 1150 F, with the first reheat to 1050 F, and the second to 1000 F. The heat rate for these conditions will be about 8500 Btu per kilowatt hour.

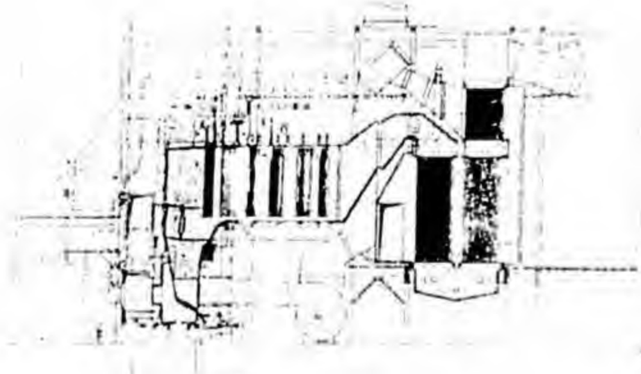
Previously we pointed out that at the critical pressure of 3206 psi, and 705 F, steam has the same density as water and therefore can no longer be separated from the water. This means that an entirely new kind of steam generator is needed. As a matter of fact, it is no longer possible to use the word boiler since water does not boil at these pressures. It instantly becomes steam.



To meet these conditions, B&W has developed the Universal Pressure Steam Generator, which can operate with equal facility both above and below the critical pressure. While this picture of the unit may seem quite complicated, you can think of it as being merely one long tube. Water enters at one end, changes to steam at some intermediate point, and becomes superheated on its way to the outlet end.

There is nothing new about this principle. Men have been working with it since at least 1824. In my own Company, we began experimental work in 1916. As the man says, the idea is simple. All that has to be worked out are the details. Believe me, the details have taken, and are taking, some working out!

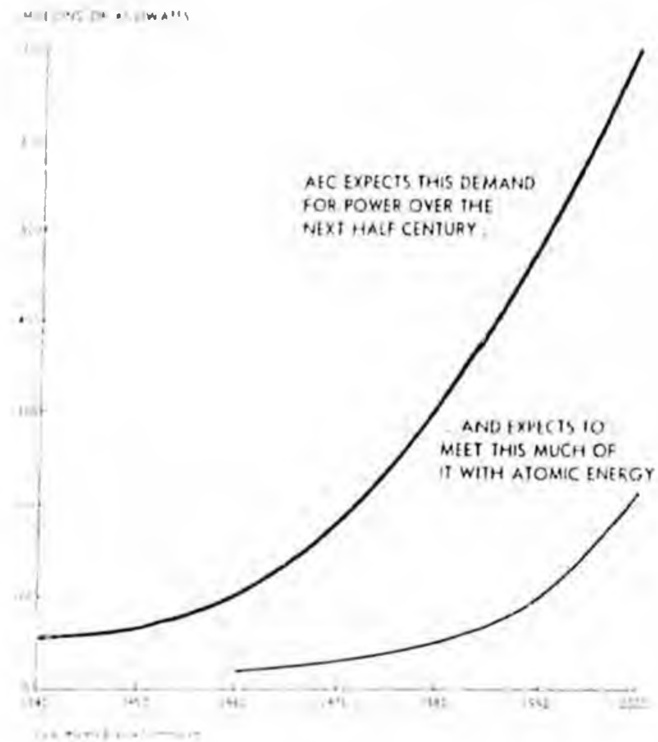
The first Universal Pressure Unit is being installed in The Philo Plant of The Ohio Power Company on The American Gas & Electric System. Fabrication has begun and it is expected that the unit will be ready for operation early in 1956. This new installation will generate 120,000 kilowatts -- three times as much as the 30 year old unit it will replace. It will fit in the same space, require little additional cooling water, and will require about 40% less fuel per kilowatt-hour. Thus will begin another entirely new era in energy conversion.



Now I know that many of you are thinking "What about Atomic Energy?" I have no doubt that when our prehistoric ancestors saw a volcano blowing its top, one or two of the less frightened, more intelligent among them might have wondered dimly how that great energy could be harnessed. As we have already seen, tens of thousands of years passed before somebody decided that steam was the way to do the job.

In the same fashion, when we saw the terrible might of atomic fission released over Hiroshima, we were anxious to know how this great force could be tamed. Again, the answer is steam or its equivalent.

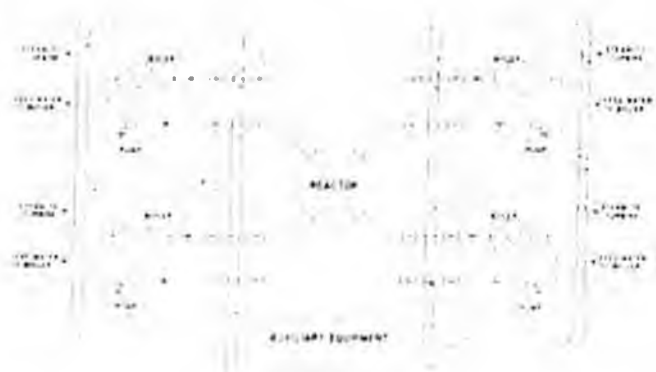
Too many people without a full knowledge of the facts have been writing about the glowing benefits to be expected from Atomic Energy. And certainly there will be many blessings in the future. But as practical, every day men, charged with immediate decision, we must keep our feet on the ground and take each step carefully.



This curve shows the rate at which the Atomic Energy Commission itself expects Atomic Energy to begin to supplement fossil fuels in the development of energy. Progress may actually be somewhat faster, but this is a fair guide of what we might expect.

The question is one of economics. How much does it cost to build an Atomic plant to generate electricity compared with a fossil fuel or hydro plant? How much will it cost to keep the plant running, including cost of fuel? Because of the great technological advances I have already described in conventional power plants, Atomic Energy plants will really have to go some, especially in the U.S., to justify their cost.

Despite this, we believe the AEC is sound in going ahead with a plant to generate 60,000 kw. As you know,Westinghouse has the responsibility for this development, and the plant will be at Shippingport, Pa. on the Duquesne Light Co. system. Two of the boilers are being built by Babcock & Wilcox Company and two by Foster-Wheeler Corp.



As this diagram shows, heat from the reactor will be used to generate steam in special boilers which will supply it to conventional turbo-generator units. While the overall construction and operating costs may be high, much will be learned from this plant that will be of considerable assistance in the development of the industrial use of Atomic Energy.

I have ranged far in this discussion of the development of the steam boiler. It would not be fair to conclude without taking a look around home.

Nobody gets very far these days, industrially or domestically, if he is not close to an electric switch.

Behind that switch is a turbo-generator, a steam boiler and a sound, progressive power company that can give its customers economical, dependable service at all times.

In North Carolina, there has been a 19% population growth since 1945. In the same time, the number of electric customers has doubled.

Your great power companies, such as Carolina Power and Light and Duke, which are among the outstanding utilities in the United States, have been able both to provide this power and keep its costs within bounds, despite the great increases in cost of construction, fuel and operation.

Behind your electric switch lies North Carolina's present and future growth and prosperity, and your emancipation. "More Steam - Less Muscle".

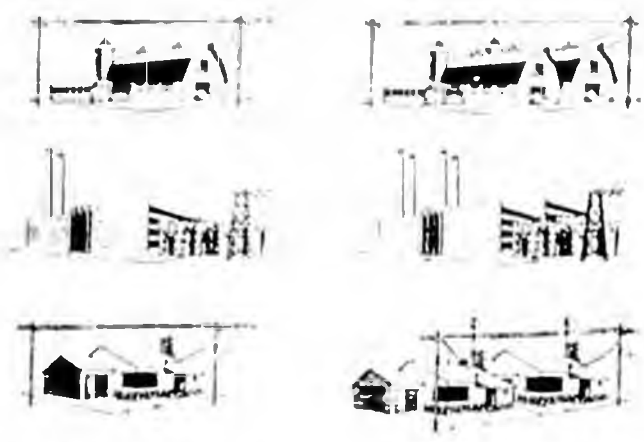
North Carolina has grown fast in all ways

19% population growth since end of 1945

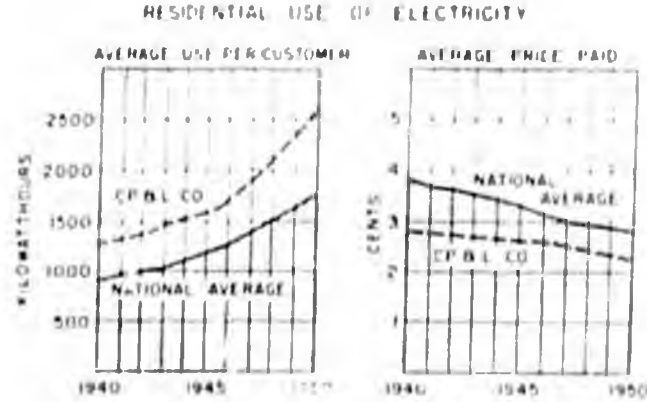
3,467,000 POPULATION END OF 1945 — **4,126,000** PRESENT POPULATION (ESTIMATE)

North Carolina has grown fast in all ways

100% ELECTRIC CUSTOMER GROWTH SINCE END OF 1945



ELECTRIC CUSTOMERS END OF 1945 — PRESENT ELECTRIC CUSTOMERS



HYDROCARBON PROCESSING

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JUNE 1991

Hydrocarbon Processing

Process Control

Estimate benefits
These five methods pass credibility tests

Reactor control
Fuzzy approach uses nonexact expressions

Integrated plant
Better productivity is the big payoff

Lab info system
Factors in selection outline enhancements

Oil fractionator
Modular control is now multivariable

VATE NICKEL IN FCC FEEDS

IANAGEMENT PREP REVISITED

IEMBRANE RECOVERS HYDROGEN

Membranes recover hydrogen

Conoco uses membrane separation to recover the hydrogen that would otherwise be lost in hydroprocessing's purge stream

K. G. Shaver, Conoco Inc., Ponca City, Okla.,
G. L. Poffenbarger, MEDAL, Houston, Texas and
D. R. Grotewold, Liquid Air Engineering Corp.,
Houston, Texas

A MEMBRANE-BASED hydrogen recovery system (HRS)[1] offers a simple, reliable and economical answer to the demand for increased hydrogen supply. The system can deliver a reliable supply of 95+% pure H_2 from offgas streams containing from 15% to 80% H_2. The [illegible] purity level of a membrane-based [illegible] allows maximum versatility in the plant use of recovered H_2. Simple, low-cost installation and an advanced, low-maintenance design contribute to HRS efficiency and economy.

An important application for the membrane-based HRS is in connection with hydroprocessing units. More hydrogen will be needed when hydroprocessing severity is increased to meet stringent government-mandated product specifications. Traditionally, the hydrogen is supplied as a byproduct from naphtha catalytic reforming, or as a primary product from steam reforming of light hydrocarbons. The HRS offers an additional supply of hydrogen by recovering the amount lost in the purge stream from a hydroprocessor's hydrogen recycle loop.

A joint venture between Dupont and members of the Air Liquide Group created the Medal membrane-based HRS. The process has proven reliable since its startup in December of 1987 at Conoco's Ponca City, Okla., refinery. The process proved remarkably cost-efficient: a simple payback was achieved in just 1.7 years.

The Conoco experience has demonstrated the profitability of the HRS, which continuously exceeds design specifications for hydrogen recovery, even with a feed rate variation from 8 to 20 MMscfd. A view of the HRS is shown in Fig. 1. Fig. 2 shows the historical feed and hydrogen product stream compositions and Fig. 3 shows the historical hydrogen recovery rate.

Operating benefits. The installation of a membrane-based HRS offers several inherent advantages to hydroprocessing

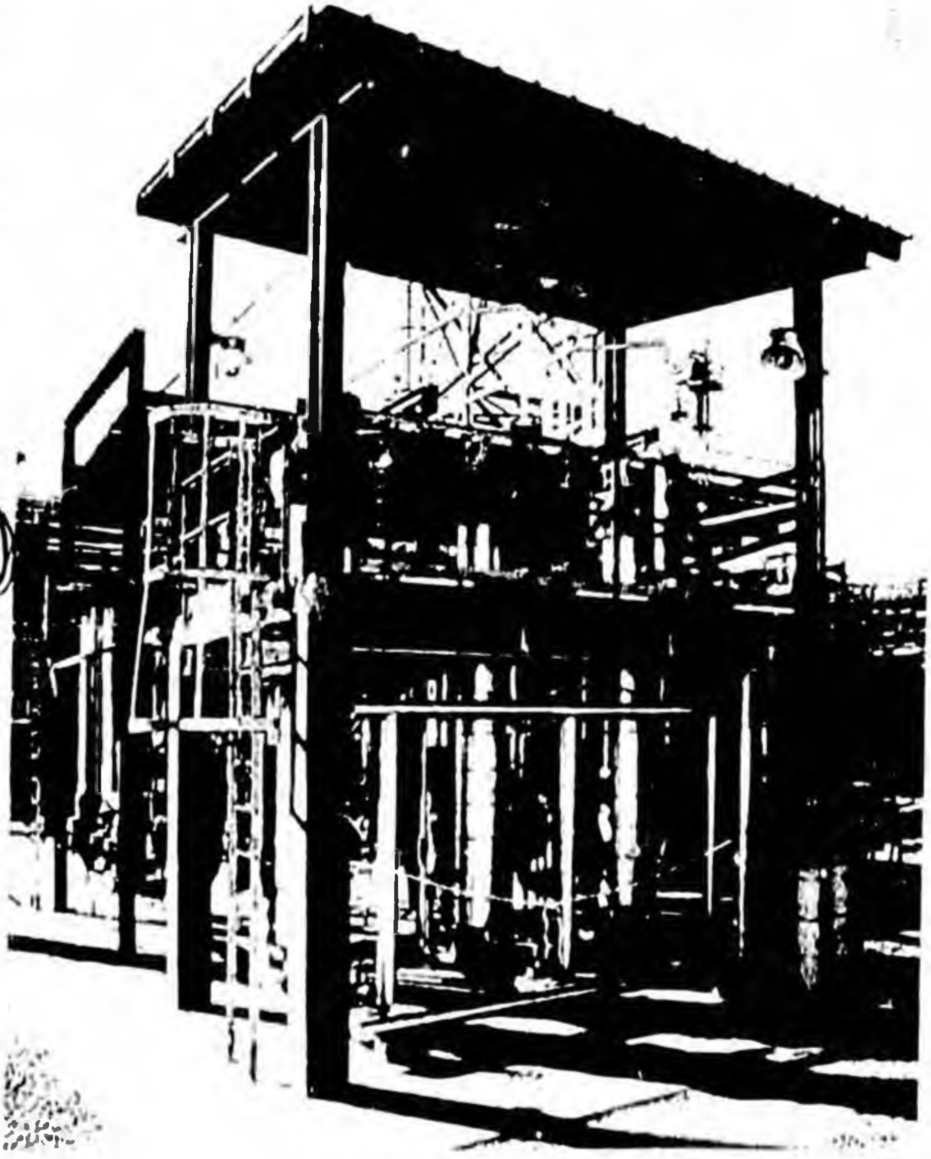

Fig. 1—View of MEDAL membrane-based hydrogen recovery system.

units. Improved product quality, increased catalyst life, greater feedstock flexibility, higher productivity, incremental hydrogen economy (the difference between hydrogen's fuel gas value and its feedstock value), and reduced power consumption have all followed the adoption of this technology.

Specific operational benefits for the Conoco commercial HRS include:

- Added value resulting from the upgrade of the coker distillate product from the gas oil hydrotreater (GOHDT) to higher quality gas oil.

- Decreased coking of the GOHDT catalyst due to a lower operating temperature accompanying the higher hydrogen partial pressure. Catalyst life has increased. This translates to increased run lengths and fewer turnarounds.

- Enhanced light cycle oil hydrodesulfurizer (LCOHDS) productivity. Fewer passes of dark oil feed through the unit are required to meet product API and color specifications.

- Longer times between regeneration of the LCOHDS unit due to the decreased operating severity possible through use of higher hydrogen concentration in the unit.

- Decreased energy consumption in the GOHDT makeup compressor due to recycle of the LCOHDS purge. The higher hydrogen purity stream allows lower volumetric flowrates of makeup gas to be compressed.

In comparison to other hydrogen recovery systems, the Conoco refinery HRS has minimal utility and maintenance costs. Utilities include low-pressure waste steam for the feed preheater, electricity for heat tracing on piping and vessels during HRS inactivity and instrument air. Maintenance for the membrane system has been limited to routine inspections, recalibration of instruments and filter element change out. The onstream efficiency of the HRS has equaled the feed gas availability.

Table 1 identifies the quantifiable economic benefits of the HRS.

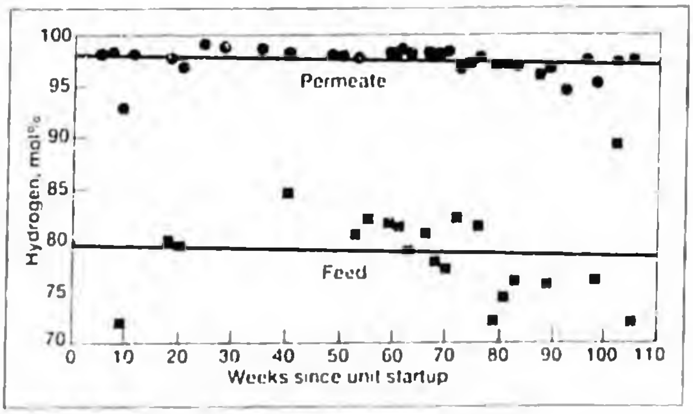

Fig. 2—Permeate retains its high hydrogen purity

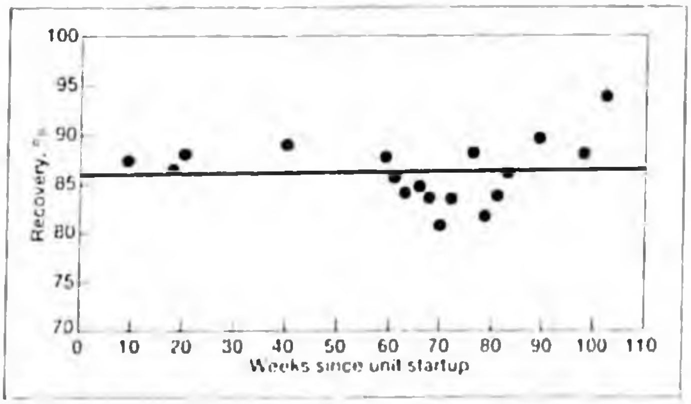

Fig. 3—Unit continues to give high hydrogen recovery

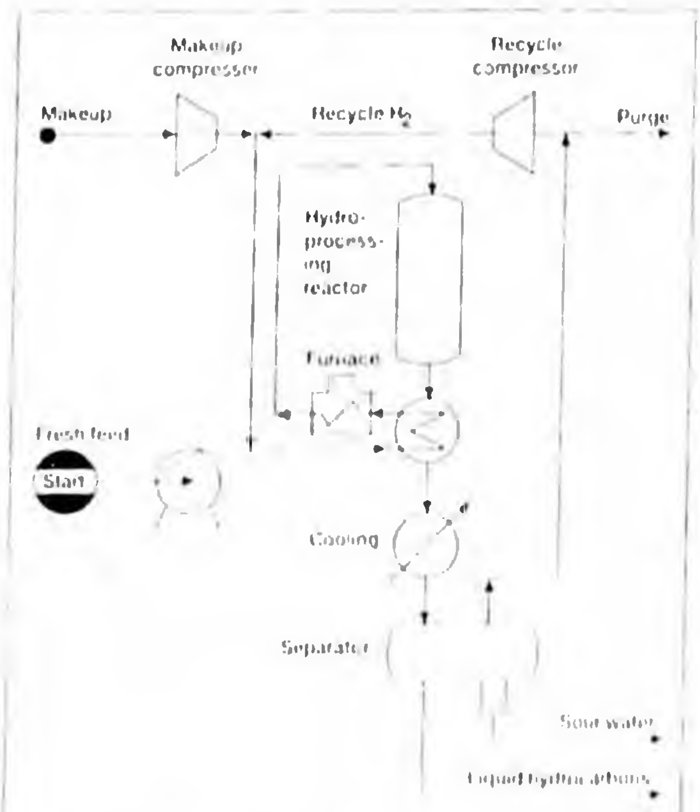

Fig. 4—Typical flow diagram for hydroprocessing

TABLE 1—HRS economics

Investment, $	662,000
Debits, $/yr	
Steam consumption	22,000
Lost hydrogen fuel value	75,000
Maintenance and overhead	29,000
Total	126,000
Credits, $/yr	
Gas oil HDT product upgrade	396,000
LCO HDS product upgrade	74,000
Reduced power consumption	42,000
Total	512,000
Earnings, $/yr	386,000
Simple payback period, yr	1.7

TABLE 2—Typical hydroprocessing unit operating conditions

Operating temperature, °F	500–800
Operating pressure, psig	100–3,000
Chemical hydrogen consumption, scf/bbl of feed	200–2,000
Purge stream hydrogen content, mol%	60–90

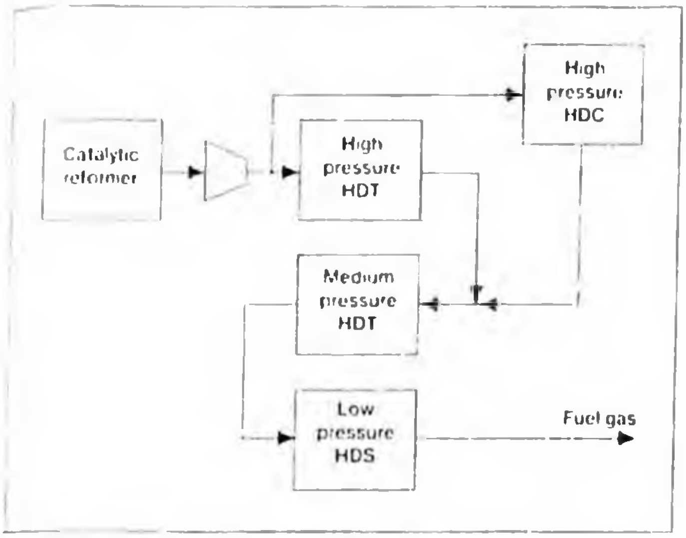

Fig. 5 – Hydrogen shared among several refinery units

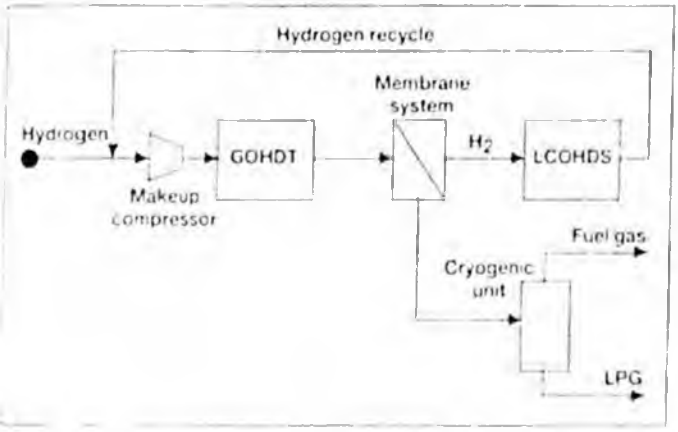

Fig. 6 – Membrane system added between two treating units

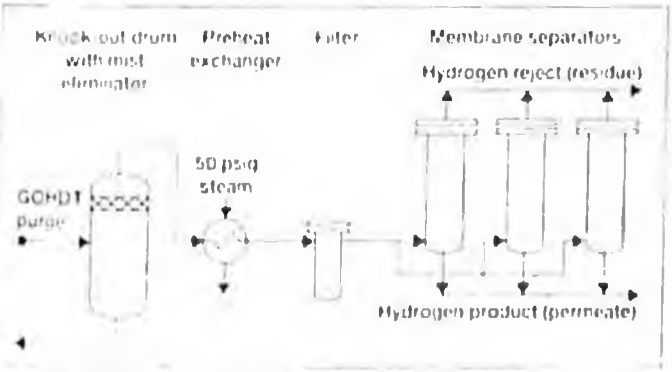

Fig. 7 – Flow diagram of hydrogen recovery system

Hydroprocessing background. Hydrogen consumers such as hydrotreaters, hydrodesulfurizers and hydrocrackers remove impurities and upgrade low-value distillate streams to more valuable feedstocks or products. The severity (temperature and pressure required to accomplish the conversion process) of a hydroprocessing unit varies with the conditions of the feedstock. High-pressure hydrocrackers are often used to convert higher boiling point materials into motor fuels. Lower pressure hydrotreaters catalytically stabilize and remove objectionable elements from petroleum products or feedstocks. Table 2 and Fig. 4 show typical hydroprocessing conditions and a typical flow scheme.

In the hydroprocessing unit, hydrogen is combined with the fresh feed and heated before being fed to the hydroprocessing reactor. In the reactor, hydrogen is consumed in desulfurization, hydrogenation, hydrocracking and other side reactions. Unconsumed hydrogen is separated from the reactor liquid products and recycled back to the reactor. The recycled hydrogen is combined with fresh makeup hydrogen prior to being fed to the hydroprocessing reactor. A portion of the recycled hydrogen is purged to prevent inert buildup.

Most refineries amine-treat the recycle stream to remove undesirable sulfur compounds and then take advantage of the pressure energy contained in the purge stream by using it as makeup hydrogen for lower pressure hydroprocessing operations. Fig. 5 shows an integrated refinery hydroprocessing hydrogen system.

The high-pressure hydrogen purge stream from a hydroprocessing unit is an ideal candidate for hydrogen recovery. With membrane technology, hydrogen separation is driven by a partial pressure difference. The recovered hydrogen can be returned to the hydroprocessing unit reactor loop as makeup or used as a high purity hydrogen stream for other hydroprocessing applications.

Hydrogen partial pressure is a key design and operating consideration for a hydroprocessing unit. For new hydroprocessing units, the hydrogen partial pressure required to achieve the desired conversion directly affects equipment sizes, pressure classifications and costs. Incorporating membrane-based HRSs into the design of new hydroprocessing units keeps operating pressure at an economic level.

In existing hydroprocessing units, hydrogen partial pressure directly affects operating severity, compression costs and liquid thruput. Installation of a membrane-based HRS reduces operating costs and/or increases liquid thruput by raising the hydrogen partial pressure in the reactor.

A membrane-based HRS was the preferred technology to recover high purity hydrogen from Conoco's GOHDT purge by using the available pressure drop to the LCOHDS.

Previously, at Conoco's Ponca City refinery, a GOHDT high-pressure purge stream, containing 71 mol% hydrogen, fed the LCOHDS and the cryogenic liquified petroleum gas (LPG) recovery unit. The purge stream was let down from the GOHDT to the LCOHDS and used on a once through basis in the LCOHDS before being purged to the fuel system.

Conoco's design specification for the HRS was to produce a stream containing 95 mol% hydrogen from the GOHDT high pressure purge stream (75% recovery of hydrogen). The available pressure drop from the GOHDT to the LCOHDS provided the driving force for the membrane separation. Fig. 6 illustrates the present GOHDT-LCOHDS system.

The HRS hydrocarbon product stream is sent to the cryogenic recovery unit for recovery of LPG. The hydrogen product from the HRS is sent to the LCOHDS and, again, used on a once through basis. Because of the high purity of the hydrogen feed to the LCOHDS, the LCOHDS offgas remains 90+ mol% hydrogen. The high purity of the offgas allows for optimum hydrogen utilization by recycling this stream to the GOHDT makeup compressor. The addition of this recycle effectively increases the capacity of the membrane unit.

Design philosophy. The feed pretreatment section contains a knockout drum, a feed preheater and a dry gas filter. Feed gas enters the pretreatment section at the knockout drum to

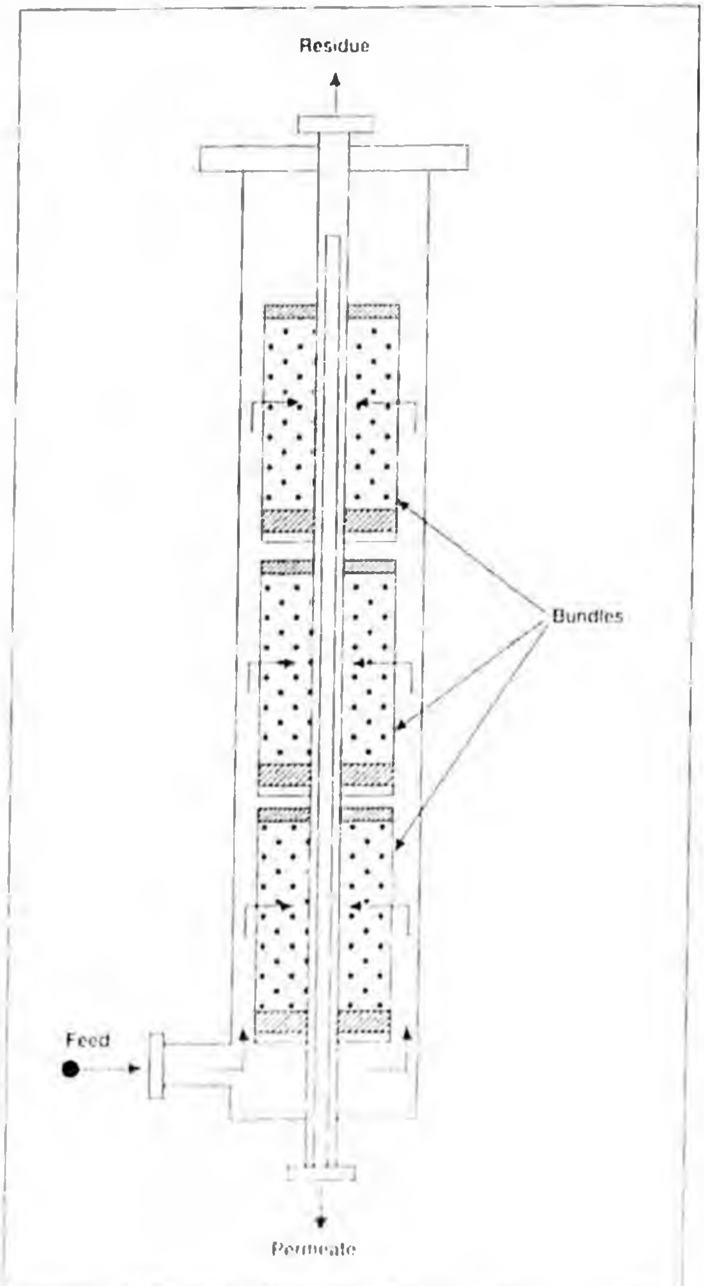

Fig. 8—Permeator uses radial crossflow separation

eliminate liquid slugs and remove entrained liquid droplets. The feed gas then passes through the preheater to provide superheat, and finally to the dry gas filter to remove any particulates before entering the membrane separation section. Fig. 7 shows a flow schematic of the HRS.

At the membrane separation section, the gas is distributed for processing into three permeator vessels. The permeators use hollow fiber membranes configured in a radial crossflow pattern as illustrated in Fig. 8. The 12-inch diameter commercial bundles resemble filter cartridges and consist of a collection of millions of hollow fibers formed together for installation into a permeator vessel.

Feed gas enters the side of the permeator vessel, is distributed into the annulus between the fiber bundle and the vessel wall, and continues to flow radially inward. As the feed gas contacts the hollow fibers, the more permeable hydrogen diffuses through the wall of the hollow fiber and is carried through the fiber bore, exiting the fiber at a lower pressure. The less permeable hydrocarbons flow around the fiber walls to a perforated center tube, exiting the permeator at approximately feed pressure.

The HRS was designed for maximum flexibility and on-line reliability. The pretreatment section was designed to handle 150% of the normal feed flowrate and the membrane separation section was sized to surpass design specifications. The feed gas preheater is a hairpin type exchanger which is specified for compactness and uses waste steam. It is operated as a flooding condenser. Unit capacity can be easily increased by connecting additional membrane separators in parallel to the existing separation skid.

The HRS is designed as a modular, skid-mounted unit. The Conoco Refinery's HRS consists of two sections: a feed pretreatment skid and the membrane separation skid. The installed unit encompasses an area of approximately 12 feet by 30 feet.

Conoco refinery personnel's experience in hydrotreating operations was used to establish the design and integration of the HRS. For example, since the amine contactor used to treat the GOHDT purge stream had a history of foaming and carrying over liquid slugs downstream, design specifications included a knock-out drum with a mist eliminator pad and liquid level control as protection for the recovery system.

The membrane performance parameters were evaluated and quantified at a pilot facility also located in Conoco's Ponca City refinery. The pilot facility is highly instrumented and computer-controlled for real-time data acquisition from multiple commercial-scale membrane bundles. Tests, using actual field gas streams with compositions ranging from 18 to 80 mol% hydrogen and pressures up to 1,100 psig, led to the development of a computer model and performance maps for this membrane system.

Summary. Conoco's Ponca City refinery substantially reduced the capital investment requirement for recovering hydrogen by installing hydrogen membrane technology. A comparison of hydrogen recovery and purification technologies indicated that the hollow fiber membrane was superior for this application. Low capital investment, low utility costs, high hydrogen recovery, consistent hydrogen product purity, minimal maintenance costs and high flexibility support the MEDAL HRS alternative. ■

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***Delbert R. Grotewold** was an applications engineer with Liquid Air Engineering Corp. at the time this paper was prepared. His responsibilities included membrane trials at customer sites. He is now with Betz Process Chemicals Inc., Woodlands, Texas. Holder of a BS degree in chemical and petroleum refining engineering from Colorado School of Mines, he is a member of AIChE.*