

**ALASKA STATE LEGISLATURE  
SENATE RESOURCES STANDING COMMITTEE  
WORK SESSION**

March 12, 2010  
3:35 p.m.

**MEMBERS PRESENT**

Senator Lesil McGuire, Co-Chair  
Senator Bill Wielechowski, Co-Chair  
Senator Thomas Wagoner

**MEMBERS ABSENT**

Senator Charlie Huggins, Vice Chair  
Senator Hollis French  
Senator Bert Stedman  
Senator Gary Stevens

**COMMITTEE CALENDAR**

Overview: Railbelt Integrated Resource Plan by Black & Veatch Consultants.

**PREVIOUS COMMITTEE ACTION**

No previous action to consider

**WITNESS REGISTER**

JIM STRANDBERG, Project Manager  
Alaska Energy Authority (AEA)

**POSITION STATEMENT:** Commented on the Integrated Resource Plan (IRP) project.

KEVIN HARPER, Director  
Consulting Division  
Black and Veatch

Project manager for the Integrated Resource Plan (IRP) project.

**POSITION STATEMENT:** Discussed the Integrated Resource Plan (IRP) project.

**ACTION NARRATIVE**

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**CO-CHAIR BILL WIELECHOWSKI** called the Senate Resources Work Session to order at 3:35 p.m. Present at the call to order were Senators Wagoner, McGuire, Wielechowski.

**OVERVIEW: RAILBELT INTEGRATED RESOURCE PLAN**  
**by Black & Veatch consultants**

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JIM STRANDBERG, Project Manager, Alaska Energy Authority (AEA), introduced himself and Kevin Harper, Black & Veatch project manager for the Integrated Resource Plan (IRP) project. He also recognized Steven Higginson, Executive Director of the AEA, who was in the audience.

MR. STRANDBERG also recognized his co-project manager at AEA, Brian Carey. He said that this process not only created an integrated plan for the Railbelt but reviewed the construction cost estimate for the Susitna project; Mr. Carey focused his work on that particular project. He explained that this is a state-sponsored integrated planning process that came about through the efforts of Representative Craig Johnson and Senator Joe Thomas. A total of \$1 million was directed towards the integrated planning and the remaining \$1.5 million of the appropriation was directed to the Susitna analysis. He recognized the support provided by the Railbelt utilities who partnered with AEA to complete the plan. From the outset their goal has been to create a relevant plan that will be useful within the GRETC concept and that has the support of the Railbelt utilities. It is a little bit unusual for a state agency to conduct an integrated resource plan; this work is normally done by a utility organization.

MR. STRANDBERG said an IRP is a grouping of defined power generation and transmission line projects arrayed on a time schedule for development that would allow for leased long run cost of wholesale power at acceptable levels of reliability. Because leased long run cost to power generation depends not only on the generators but also on the transmission lines and fuel supplies, this analysis included a thorough integrated review of the transmission system for the Railbelt as well as an examination of the potential energy and fuel portfolios for the power generation that is proposed. He said Mr. Harper would discuss what is included in the plan, how it can be used, what the key results are and perhaps give them some insight into how to interpret them. He concluded saying this RIRP defines what energy projects should be constructed in the future in the Railbelt; and GRETC is a generation and transmission (G&T)

corporation that will be responsible for building these future energy projects and will immediately make use of this product after it is formed. It is likely that many of the projects which urgently need to be undertaken will be undertaken under the framework of this IRP.

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KEVIN HARPER, Director, Consulting Division, Black and Veatch, said he was the overall project manager on this project and that he would provide an overview of the results.

The first slide (3) showed the amount of energy by different technologies over a 50-year period starting in 2011 going to 2059. He pointed out a significant reduction in the use of natural gas in the first 15 years and then a slight increase, but at the end of the period less gas is being used than is currently in the Railbelt. Second, he noted a yellow "sliver" in the middle of the graph that showed existing hydro along with two more that were selected in the plan - Chakachamna, a large project, and Glacier Fork. The combination of generation resources and related transmission investments shown in the "preferred resource plan" represents \$9 billion of capital investment over the next 50 years. He also pointed out that this resource plan results in dependence on renewable technologies much more than current dependence which becomes 62 percent of total energy requirements in 2025, and when you look at the wholesale power costs that comes from this resource plan it's a little bit more than 17 cent KWh including inflation and is around 12 cent KWh without inflation.

CO-CHAIR MCGUIRE said there is a lot of talk about that number and she asked how they got it.

MR. HARPER explained that the relevant number to talk about is the 12 cents because that is without inflation and if you compare that to current costs which are around 9-10 cents, it represents the fact that the costs will go up with \$9.1 billion worth of capital investment that is required to address several issues, one being the aging infrastructure both on the generation and transmission side, but also in order to meet a moderate amount of growth going forward into the future.

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CO-CHAIR MCGUIRE asked what factors he looked at for the 9-10 cents.

MR. HARPER replied that the 9-10 cents was the average wholesale power cost that is currently being paid by the Railbelt utilities' ratepayers. That is all of the costs for generation and transmission using existing resources, but not including the distribution costs.

CO-CHAIR MCGUIRE asked if it included Fairbanks' costs.

MR. HARPER answered yes.

CO-CHAIR MCGUIRE asked if the analysis included new energy projects such as Mt. Spurr and the Fire Island wind.

MR. HARPER said this resource portfolio is based on an economic analysis of all commercially available technologies the Railbelt could rely on; it includes conventional technologies like natural gas and coal and renewable technologies such as wind and geothermal. Their modeling had two types of resources, specific projects and generic projects. It included Fire Island, Mt. Spurr, Healy Clean Coal, and Southcentral Power Project as specified projects, essentially using the cost information they got from the utilities or the proponents.

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CO-CHAIR WIELECHOWSKI asked if slide 3 is what he is projecting will happen or what should happen.

MR. HARPER said this is the "preferred resource plan" in Black & Veatch's report in terms of what the generation resource mix ought to be as well as a series of transmission projects that they recommend be developed by the utilities or GRETC going forward.

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SENATOR WAGONER asked if their plan made any comparisons to any other geographic area's recommended plan in the United States.

MR. HARPER replied that this plan was designed specifically for the Railbelt using technologies which are available and using estimates about costs that are relevant to the Railbelt. However, if you compare what comes out of this plan to what is occurring elsewhere, you would see a number of similarities. For example, a more diversified portfolio of resources which is what you see elsewhere. Of the \$9.1 billion approximately \$1.6 billion is related to transmission investments. That investment would get a transmission system with redundancy and reliability like in the Lower 48. This portfolio has a greater reliance on

renewables, which is consistent with general trends elsewhere. It also includes a fairly significant impact from demand side management in energy efficiency (DSM/EE) programs, which is generally consistent with what happens elsewhere.

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CO-CHAIR MCGUIRE asked if the dates next to the projects on slide 4 are fixed dates or what is feasible.

MR. HARPER answered that for each of the available resources they used a combination of costs and performance assumptions. They did not put any constraints on the model in terms of which resources it selected and when it would select them except for, in some cases, a particular option would not be available for a certain period of time. For example, large hydro cannot be selected for the next year because it would take around 15 years for licensing, et cetera. The model using straight economics does a comparison on the lifecycle basis as to which combination of resources would result in the lowest cost on a present value basis. It is a freely chosen resource mix, the only constraint being the amount of time it takes certain resources to be on line.

He showed a slide of the G&T projects in their preferred resource plan within the first 10 years; the dates in the parenthesis are the dates that the resource would be on line and producing power. The first resource is a combination of a number of different DSM/EE programs and measures. They allowed the model to pick those resources based upon the economics. As a result, they have been able to reduce the region's energy load by about 8 percent.

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One of their key assumptions was that when people make a decision to lower their energy usage and go out and buy high efficiency refrigerator they will pay extra for it. If that is \$100 and there was a \$50 rebate from the utilities or a regional entity, the cost in the resource plan is 50 percent of that incremental cost. On this particular resource they capped the amount at 8 percent. While a higher rate may be achievable (some utilities have achieved 15-20 percent), they didn't think this first resource plan would be the right place to start, because a couple of factors are unique about the Railbelt - it has limited data and experience with energy efficiency, it is an isolated network, it has severe weather conditions, and there is a limited amount of electric space heating in the region.

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So they started with 8 percent as a reasonable target, but acknowledge that it could go higher. The next projects shown were:

- Nikiski Wind project coming on line in 2011 under active development
- Healy Clean Coal Plant which is largely complete in terms of capital cost
- Fire Island Wind - 54 MW - \$174 million project coming on line in 2012
- Southcentral Power Plant currently under development by Chugach and Anchorage ML&P - 180 MW, a \$370 million investment
- Glacier Fork Hydro project - "run of the river" project which means there is no dam or storage involved - 75 MW at \$330 million under preliminary development
- Two municipal solid waste projects in Anchorage and Golden Valley, not under development currently - economics are based upon similar projects elsewhere; assumptions with regards to the amount of solid waste in those two areas were used - in Anchorage it's roughly a 22 MW plant and in Golden Valley it's a 4 MW plant
- Retrofit at the North Pole facility in Golden Valley - adding to the existing plant - 60 MW, a \$80 million investment
- Mt. Spurr Geothermal 2020 - 2 units at 50 MW each - what Ormat believes is the potential resource there

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CO-CHAIR WIELECHOWSKI stated that Ormat said they would be on line closer to 2016 and he wondered how they came up with some of their dates.

MR. HARPER replied that the model is constrained so it can't pick a resource before it could be on line, but they didn't tell the model to force it to be on line the first year that it could be chosen. The model sets a direction towards higher use of renewables including geothermal and hydro. It picked Mt. Spurr for geothermal and 2020 being the best year for it to come into production on an economic basis. That's not to say that it shouldn't come on in 2016 or 2017, because their analysis assumed no state grants or federal money on any of the resources. If the Mt. Spurr project comes on line by 2016 it can take advantage of significant tax credits, and they have

committed to sharing those benefits with the ratepayers - which would argue for bringing it on sooner than what the model says.

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A significant recommendation is continuing development of Susitna/Chakachamna/Glacier Fork on a parallel path. He explained that their preferred resource plan includes Glacier Fork and Chakachamna, but not Susitna. However the quality of assumptions that were used in the case of Chakachamna and Glacier Fork are not as solid as they are for Susitna because those two projects have not been studied to the degree that Susitna has been. Susitna went through significant work in the early 80s when HDR was hired to resize the projects for the Railbelt and update the capital and operating experience. The quality of the input assumptions is better than what they had to work with for the other two. In their view Susitna efforts should move forward in terms of development and Chakachamna and Glacier Fork should continue with a "fatal flaw" analysis. Chakachamna by its nature has some issues that have to be looked at in more detail to ensure that capital costs are solid and that it could be built and operated. Glacier Fork estimates are in a similar situation.

SENATOR WAGONER asked what those issues are.

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MR. HARPER said in the case of Chakachamna, the detailed engineering work hasn't been done. It also moves water from one river to another and a number of environmental issues are associated with that. In their view, there have not been enough work and discussion with the resource agencies to understand whether that would be acceptable or even if it is acceptable, what type of constraints would be put on the operations to address the environmental impacts. It's also located at the base of a glacier and a volcano which raises further issues. This is consistent with issues the TDX folks have said need to be addressed before they know the project is something that can go forward.

The last item is related to transmission. AEA's report has roughly 20 specific transmission line projects. They fall into categories; one is projects that are repair or replacement of existing transmission assets that are required to insure that the reliability of the existing system is maintained. Another set of projects is the expansion of the existing transmission system which would allow more power to be moved up and down the

grid as well as providing more redundancy and reliability. Those combined projects run about \$1.6 billion of investment.

After discussions with the utilities they identified projects that should be completed within the next five years. The first three are in essence repair and replacement of existing lines on the network - retaining current reliability. The fourth project is a new line that would be aimed at improving the ability to move power up and down on the line. The last three projects are additional southern Intertie in terms of routing, an important next step with some investments being made after the first five years.

SENATOR WAGONER said he didn't understand, for instance, that Homer Electric buys 10 or 12 percent of the power generated at Bradley Lake. They buy additional power from Chugach Electric and that power is shipped down the grid to them. Does this study look at exchanges of power generation and power capacities even if Homer Electric has to pay 1 cent KWh because of the difference in the production cost instead of looking at all the money to be spent on transmission lines? He knew they would "run into a lot of trouble" in trying to increase the size of the transmission line that runs through the Kenai Wildlife Refuge.

MR. HARPER answered that their modeling effort looked at the tradeoff between having more transmission capability versus having more local generation; and based upon that analysis, investment in additional transmission line made economic sense. But he agreed that there would be challenging issues associated with whether the line could be built and what the right route of that line would be. Doing that detailed analysis is in essence what one of the projects is.

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MR. STRANDBERG noted that their team included Electric Power Systems as a reliability consultant. He said arrangements to trade the power like Senator Wagoner suggested do exist. But he said that Bradley Lake is not a large reservoir of water and it can't put out 110 MW 100 percent of the time. It can effectively average 30-40 MW over the year; so the Kenai Peninsula will still need secure and reliable transmission capability.

SENATOR WAGONER said that's why he asked that question. He would much rather put money into projects that are directly related to areas than he would spending hundreds of millions of dollars on transmission lines running across the state that they may or may not be able to build.

MR. STRANDBERG agreed and said the analysis has been to minimize the amount of transmission that would be required over the long run.

MR. HARPER said the last project listed is Battery Energy Storage System (BESS). The need for regulation of the frequency on the transmission network becomes a greater challenge when you become more dependent upon resource that you cannot control when they are generating electricity. In other words, non-dispatchable resources like wind have a greater challenge in regulating frequency. He said BESS is in essence a placeholder of one possible solution for what would be necessary. Additional work is needed to decide exactly how much is needed and whether this technology or some other option would be appropriate. It is an additional cost, however, in the neighborhood of \$50 million plus or minus 50 percent; and it was important to include it in their total capital program.

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MR. STRANDBERG added that they always kept the uniqueness of the Railbelt system in mind. The Lower 48 has large amounts of renewable energy - wind projects and established procedures and equipment on the grid - it's relatively easy to integrate a wind project into a grid there. The regulation of the project can be secured either purchasing ancillary services or other arrangements, but in Alaska the network will be easily influenced by large scale wind projects. He said their analysis isn't done yet.

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MR. HARPER said slide 6 shows the impact of DSM/EE. The top curve is what the load would be if there was no DSM/EE and the bottom is the result after including the selected programs. It indicated roughly an 8 percent reduction in energy requirements and about a 10 percent reduction in peak load requirements.

SENATOR WAGONER asked what they calculated into their energy efficiency figures. Did they use schools or municipal facilities?

MR. HARPER answered that they used a comprehensive set of measures for both residential and commercial facilities. In the residential market they looked at 50 specific measures including switching out lights, weatherization, efficient appliances and things like that. In the commercial facilities they looked at similar things. They did not include any measures for military

or industrial facilities, because those are very sight-specific and it was hard to come up with generic numbers to work off. They also didn't include specific rate design options that are available to influence behavior; those include real time pricing, demand response pricing and so forth. Part of that is just because they are hard to model and the data isn't Alaska-specific to know how consumers would behave if you tell them that the cost of power peak time is more than off-peak time. He said they covered residential, commercial, school and government buildings well, and that's how they came up with the 8-10 percent. But because they didn't include industrial, military or innovative rate designs is why they think more DSM/EE is possible in the region.

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CO-CHAIR MCGUIRE said she assumed AEA would update their models as things like the omnibus bill passes.

MR. HARPER agreed that updating the IRP on periodic basis is important, typically every 3-5 years. Part of the reason is to reflect new policies and new knowledge about uncertainties in energy services.

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Slide 7 graphed annual wholesale power costs over 50 years for a number of different cases; 1A and 1B refer to a scenario of load growth where they took current load with moderate growth over time based largely upon the current load forecasts of the utility. In the case of 1A they allowed the model to pick resources based upon straight economics; in 1B they forced the model to select resources that would result in at least 50 percent renewables by the year 2025. The reason was to answer the question of whether there is an incremental cost to achieving the target put forward by ex-governor Palin.

MR. HARPER noted a major conclusion of the study is that the cost of the resource plan for 1A and 1B are the same; and what that says is that there is no incremental cost to 50 percent or greater renewables by the year 2025.

MR. HARPER said that two cases resulted in lower costs than the 1A and 1B scenarios; one did not include any CO<sup>2</sup> taxes and the second doubled the DSM/EE. Their base cases had assumptions regarding what the cost of CO<sup>2</sup> taxes would be and was based upon the legislation currently working through Congress and economic analysis done by the Energy Information Administration and the Environmental Protection Agency. So they assumed there would be

a CO<sup>2</sup> tax that would impact all fossil fuels. Sensitivity cases labeled 1A and 1B showed a significant reduction in costs if there are no CO<sup>2</sup> taxes. What drives that cost is not just the fact that you don't have those taxes, but a different resource mix. In fact, the amount of renewables you get by the year 2025 is a little bit more than 30 percent in that sensitivity case versus the 63 percent that is in case 1A and 1B. Essentially that means that if you have no CO<sup>2</sup> tax you continue to rely more heavily on natural gas than under the assumption that that you have CO<sup>2</sup> tax.

The other case of lower cost is where they arbitrarily doubled the impact of DSM/EE programs, which results in a little over \$1 billion of savings over the 50 years. They cautiously think there is a potential for that level of savings but they wanted to be conservative and used it as a sensitivity case as opposed to a base case input assumption.

MR. HARPER said they also looked at what happens if you have higher gas prices than what was assumed, what happens if you don't allow the model to pick Chakachamna, and so forth.

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Slide 8 he referred to as the "capital gap slide" and explained that as part of the project the AEA hired Seattle Northwest Securities to do some financial related analysis. They essentially were asked to do two tasks. The first was to look at the available debt capacity of the six Railbelt utilities and try to answer the question: can they finance the future on their own. The second question they were asked was to look at some options for financing and rate design that could help mitigate the rate impacts that would result from this resource plan.

This slide addressed the first of those two tasks. They analyzed the current debt obligations of the six utilities using standard measures that are used in the financial markets and came up with a regional number. The bottom two lines have a range of low debt capacity and high debt capacity, which was their estimate of how much additional debt the utilities could take on. The top line is the capital expenditure requirements coming out of the resource plan that equals roughly \$9 billion. Even under a high debt or optimistic case there is roughly a \$5 billion gap. That was the result of the first question.

How is that gap addressed? The state doesn't have to necessarily fill it; it's their opinion that if the regional entity, GRETC, is formed and goes to the market as one entity looking for

capital there are benefits rather than having the six individual utilities going to market on their own. The transmission network is limited as it is today, he explained, not because the utilities don't understand the value of a redundant transmission network, but because the market is so small that you can't get the economics to work out. So their view is that the utilities on their own wouldn't be able to finance a \$1.6 billion transmission plan.

CO-CHAIR MCGUIRE asked what role independent power providers (IPPs) play in their assessment.

MR. HARPER said they were agnostic as to who owned or who developed projects. That means when they looked at specific projects they looked at the underlying economics. Fire Island, for example, since that is being proposed by an IPP, they took cost estimates from CIRC that were specific to the project, but just capital costs and operating performance. They did not assume that the project would be financed using CIRC money or using their sources for a couple of reasons; one is that they don't have access to that information. In essence they assumed there would be a utility-type of entity making the capital investments in these projects using standard utility capital market instruments. This says you can think of this resource plan as a benchmark. So, suppose another wind project is being developed, you would want the developer to put forward their best proposal to the utilities or to GRETC; if that deal is better than what is in the resource plan then it would make sense to go with that option. So, this would become a benchmark that allows IPPs to come in with proposals, and if their projects make sense, then the developers have the opportunity to come forward and get selected.

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MR. STRANDBERG added that he expects the way GRETC would use the IRP document would be to look at the array of projects and make some determination about how they would like to procure power supply. The board would possibly entertain ways of advertising for power projects. This is the way it is done in the "states." The GRETC framework allows that process to occur, but the actual analysis of the projects is done on a straight up economic basis without regard to how the thing might be built.

CO-CHAIR MCGUIRE said she thought it was important to assess along the way how critical certain pieces are. She saw at least two projects that were IPPs that are integral to the overall rate they have.

MR. HARPER added that projects developed by IPPs represent two potential opportunities for the region; number one it helps to address this \$5-million capital gap. Second is that allows free enterprise to occur and allow people to come forward with projects; they have to be economic and reliable.

CO-CHAIR WIELECHOWSKI said this is a good discussion to be having and timely because they are wrestling with the whole issue of how to regulate and incentivize IPPs. He asked Mr. Harper if he had any insights on how independents should be handled by the state.

MR. HARPER said it's hard to answer that in a generic way because each project is very specific. Developers have their own sources of capital and can qualify for certain types of federal incentives dependent on technology, timing and the developer themselves. His personal feeling was that putting in place a solid competitive power procurement process so that they know what the rules are and that the analysis gets done would be important; and then providing incentives to specific projects that help achieve the policies the legislature feels are important.

CO-CHAIR WIELECHOWSKI asked if putting a power procurement process in place would be done statutorily and do many states do that.

MR. HARPER answered that a number of states do that. For instance, in Seattle the power company he buys his power from got out of the business of building power plants a number of years ago. So, they go out and have request for proposals (RFP) for specific types of power at various times and have a process that is in place. British Columbia (BC) is another example of an electric utility that has largely gotten out of the business of generating power. It is a model that has been shown to work elsewhere. They have been structured in a variety of different ways, but you can learn from that as opposed to having to start from scratch. These things are set up either by statutory language or regulatory rulings and each state addresses that a little bit differently.

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CO-CHAIR MCGUIRE said she asked Legislative Research to look at regulation of wholesale transactions by IPPs and briefly they said that no other state regulates independent power producers the way Alaska law now dictates. IPPs in all of the states they

researched are regulated by the FERC but are not subject to state regulation. It is widely viewed that having a second level of RCA regulation is a business disincentive because most states have the same provision Alaska does which says if they are selling to a utility they have RCA oversight but not of the IPP itself. Her concern in the long run is that it will ultimately discourage alternative and renewable energy IPPs, in particular, from getting into the marketplace and Alaska wants more competition not less.

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MR. HARPER agreed. He said regulatory oversight usually comes in with the power purchase agreements (PPA) as being prudent or not on the part of the entity purchasing the power. And to the extent that there is a competitive power procurement process in place either by legislative mandate or regulatory ruling that often means there is regulatory oversight of the process and review of the results to ensure that the analysis and selection followed the established rules.

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MR. STRANDBERG commented that because much of the Lower 48 power that is produced and transported goes across state lines it is interstate commerce. So for many parts of the Lower 48 the FERC has jurisdiction over the G&T. It has extensive rules and has created a quasi-competitive market. The vast majority of state regulatory agencies in the Lower 48 really have jurisdiction over the distribution function with some shared jurisdiction for transmission and generation. FERC doesn't have jurisdiction very much in Alaska because of the lack of state lines; the RCA is the only regulatory agency here.

CO-CHAIR MCGUIRE said it may not be a choice between what we have now and simply eliminating RCA; it might be a choice of something else they hadn't considered yet. The chairman and many consumers are particularly sensitive to the Enstar ConocoPhillips debacle; the fact remains that nine years later, no RCA contract was approved and consumers are left in a lurch with the potential for brown outs. She maintained that if they would have adopted the Henry Hub contract five years ago, they would be at \$4.45 today and happy.

She said the chairman rightly points out that the RCA, being the only game in town, asked questions about profit margins and process, and those commissioners did not feel they got the right answers. She wondered if there is some other way to inject by way of process as opposed to another layer.

CO-CHAIR WIELECHOWSKI recognized that Representative Fairclough joined the committee.

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MR. HARPER said slide 9 addresses the issue of committed units. This phrase is used to include projects that are currently under development or being proposed by the six Railbelt utilities. These are projects that were selected outside of a regional planning process, but they are projects that the utilities are moving forward with, and in their view, make sense, because the utilities don't know if GRETC will get formed and they still have to keep the power on. These "committed units" include Healy Clean Coal, the Southcentral Power Plant, a couple of projects in the Homer area, and several projects in ML&P.

They ran a sensitivity case forcing the model to accept or select those projects, and there is a 4-percent cost difference where the utilities going forward with their current plans would result in higher cost to the region. This analysis had some limitations. To have done it correctly each of the six utilities would have had to develop an integrated resource plan to compare with the regional one. And that wasn't within the scope or the budget of the effort. Also two things lead them to conclude that this 4 percent (\$450 million) difference is understated. One is they assumed that the same level of DSM/EE would occur in both cases and they assumed that the same amount of transmission investment and transfer capability would exist in both cases. He suggested that if the utilities continue moving forward on an individual basis it's likely they won't reach the DSM/EE levels because they are asking six utilities to develop six different programs which is inherently much more challenging than having a regional entity develop one program. And it's hard to imagine how the individual utilities would be able to spend \$1.6 billion in transmission. But he said the utilities are doing what is appropriate for them to do until a decision is made with regards to the regional entity.

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MR. STRANDBERG added that they worked very hard to have the utilities with them as they designed the architecture of the study. This committed unit issue in particular between MEA, ML&P and Homer Electric is a sensitive one and they recognize and understand those sensitivities.

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MR. HARPER said Seattle Northwest Securities was asked by the AEA to look at two issues; one was the capital raising capability of the individual utilities and the second was looking at some options related to financing and rate design that would help address the rate impact of a \$9.1 billion capital program.

Slide 10 talks about that second piece of their analysis. They looked at a base case and an alternative case; their base case assumed that all of the capital program would be financed using standard capital market financing. In the alternative case they looked at the options on the left as ways to address financing and spread out the rate impact. These are not recommendations on their part or his part, he emphasized; that was not the purpose of the analysis and is the subject of additional analysis that would be done in developing a finance plan. These were options that are in place in other places where they looked at the impact.

Those options are first a ratepayer benefit surcharge. This is essentially starting on the first year all ratepayers would pay 1 cent per KWh for the first 17 years (when the really big upfront capital is done in terms of the transmission and hydro). So that, in essence, creates a pool of money that reduces the amount that is needed to get from capital markets. It is prefunds projects before they are up and running and generating electricity, which is counter to current ratemaking procedures in Alaska (wait until the projects are generating electricity before you start recovering).

Second is what they refer to as Pavel financing where as you go to the markets and raise the money to cover the debt of that capital. Then over time as your capital program becomes less, you generate more revenues than you need and that allows you to pay for future capital projects without going to the markets.

The third technique is a tool that is used in a number of states where a project is under construction and the utility is allowed to start charging rates to cover the interest of the capital that is raised on that project. Then when the project is up and running they start having rates that cover all of the costs. In essence what that does is take out the interest that would be incurred during the construction period so that you wouldn't be paying interest on interest. Again, this asks ratepayers to pay before projects are up and running.

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The fourth item was an assumption that there would be a \$2.4 billion zero-interest loan from the state modeled after the Bradley Lake model.

MR. HARPER again reminded them that these are not recommendations either by Seattle Northwest or by Black & Veatch but these are options that were considered. The important take-away from this is the maximum rate and the average rate. The costs are related only to the recovery of capital; it does not include fuel and O&M. The average rate is the same - 7 cents KWh and 6 cents in the alternative case (paying 1 cent per KWh and basically paying the same average rate). This basically says there is no free lunch out there. So, even if the state puts up the money, as long as there is going to be repayment of the money there will be similar average rates. The important thing is the maximum rate that goes from 13 cents in the base case using standard capital market financing down to 8 cents. That says there are these tools and there are others to be considered that would allow them to reduce the rate impact as the large projects are brought on.

It also achieves intergenerational equity. If you are bringing a large 100-year hydro project on line and you're recovering all of the costs for that project in 30 years then in essence you have customers in the last 70 years that are going to pay significantly less than those in the first 30. Tools like this allow that to be spread out over 100 years. He concluded saying he would be happy to answer questions.

[4:55:50 PM](#)

CO-CHAIR WIELECHOWSKI thanked him for a very informative presentation and adjourned the meeting at 4:55 p.m.