BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-6)

REQUEST FOR PROPOSALS

Evaluation of Resources
from Electric Energy Efficiency and/or
Power Supply Resources

Avista Corporation

August 2000

Introduction

Avista Corp. is seeking to identify resources that can become part of Avista's resource portfolio to meet its system requirements while at the same time minimize the cost of meeting those needs. Resources bid to Avista will be considered for purchase as part of the company's long-term resource portfolio for meeting customer needs. The company has identified a power need of approximately 300 megawatts (MW) of both capacity and corresponding energy. Resource availability in the year 2004 would fit Avista's requirements best. However, Avista does have significant resource needs in advance of this time frame. Bidders wanting more details regarding the timing of Avista's resource needs may request a copy of its "1997 Integrated Resource Plan Update".

The goal of the 2000 Request For Proposals (RFP) will be to identify low cost and environmentally sound resource options that best satisfy Avista's resource needs. This process will support the company's ongoing assessment of the cost and availability of new resources, and may provide input for Avista's 2000 Integrated Resource Plan (IRP). Resources bid to the company in response to this RFP must be competitive with other resource options available to Avista, including resources available at cost from affiliates, in order to be considered for purchase.

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This RFP is an all-source process and bidders are encouraged to make proposals for energy efficiency resources or power supply resources. Avista encourages bidders with competitive renewable resource projects to consider bidding as a power supply resource. Proposals from energy efficiency measures will be competing against each other and power supply resources will be competing against other power supply resources. The most favorable resources bid to the company will also be compared with Avista's own potential or existing resource acquisition programs for either energy efficiency or power supply resources respectively. Avista has included information on its energy efficiency programs and on general power resource needs and costs in its "1997 Integrated Resource Plan Update".

Avoided Cost

The following table represents costs that Avista might incur were it to construct a large combined-cycle combustion turbine. The avoided costs shown below for the next 20 years (excluding 2001) are based upon this resource assumption.

Avista Utilities Avoided Cost Schedule
nominal dollars

Year	$/MWh	Year	$/MWh	Year	$/MWh	Year	$/MWh
2001	60.0	2006	39.1	2011	44.2	2016	51.2
2002	37.8	2007	39.9	2012	45.4	2017	52.9
2003	37.7	2008	40.8	2013	46.7	2018	54.6
2004	38.0	2009	41.8	2014	48.2	2019	56.3
2005	38.4	2010	43.0	2015	49.7	2020	58.1

For 2001 the avoided cost value is based on actual broker quotes obtained July 24, 2000. Between 2002 and 2020, the figures are generated using a spreadsheet analysis prepared by the Northwest Power Planning Council (NWPPC). The spreadsheet was adjusted to reflect the NWPPC's *250 MW CC - Eastside Blk 1 Base* case, and one hundred percent investor-owned utility ownership. As shown, the avoided cost rises from $37.8 in 2002 to $58.1 in 2020.

The figures shown generally are representative of the costs that the Company might expect associated with the construction and operation of a combined-cycle combustion turbine. However, it is important to recognize that a number of variables might change, such as where the project ultimately is constructed.

Gas price assumptions can vary the project economics substantially. Natural gas prices were input into the NWPPC model using data from the Company's natural gas 2000 Integrated Resource Plan. These values are higher than the NWPPC's assumptions and drive costs up by about 5 percent in the first year.

Another important consideration is environmental compliance. Permitting processes and requirements for air quality, water and mitigation of other environmental impacts will also vary depending on the specific project location.

While the avoided cost figures shown above meet the requirements of WAC 480-170-050, the company expects the RFP results to provide a better measure of avoided costs going forward. As such, a given proposal that provides a cost stream below the costs shown above might not be selected. Similarly, where the RFP shows that general market conditions are higher than the above schedule, Avista may select a project with costs above the avoided cost schedule.

General Considerations

The Company states certain resource preferences that would fit well into in its resource portfolio. However, bidders may submit proposals for projects of varying types or sizes, or at alternative sites. Timing of resources may vary from what is suggested as well. Each variation may have distinct pricing characteristics.

Potential resources will be considered for acquisition as part of the company's long term resource portfolio for meeting retail customer needs. The company will consider all relevant factors (including but not limited to price, dispatchability, transmission impacts,

other bids, company-sponsored options, business and operating history of the project developer, and financial and rate impacts) in the bid resource evaluation. Resource proposals will be evaluated on the basis of the most current information available. Evaluation is discussed in more detail under both the energy efficiency and power supply sections.

Avista retains the right to reject any and all project proposals, at any time before execution of a written contract. Executed contracts may be submitted to the IPUC or WUTC for approval, as appropriate in Avista's judgement.

The bid term, or the length of time the electrical savings or electrical generation is being bid, shall be set forth in each proposal. However parties are advised that Avista is interested in long-term arrangements that will meet resource requirements for twenty years or more.

Aspects of the sponsor's proposal may be subject to negotiation to specifically define the operation of the proposed project, to insure adequate credit support for the prospective seller, and to insure that the delivered services will be consistent with Avista's needs. These negotiations will be important in shaping the quality of the bid services to ensure that they add value for the company. Negotiation with a given sponsor does not necessarily imply that such sponsor's proposal will be selected.

To review each proposal fairly and to determine which projects are likely to provide the best value to Avista's customers, Avista requires specific information regarding each proposed project.

Proposal Preparation and Evaluation

Project sponsors interested in responding to Avista's RFP must complete the appropriate forms and submit them according to the RFP schedule. Avista will commence its

evaluation of the RFP submittal at the time of the bidding deadline as outlined in the Evaluation and Ranking sections under the Request for Energy Efficiency Resource Proposals and the Request for Power Supply Resources respectively. To assure full consideration of the bid, as well as to expedite the review process, please adhere to the RFP instructions and response format. It is important that all information requested in the RFP be complete and submitted by the bidding deadline. In the initial review of the bid proposals, if deficiencies are not material, Avista may, at its option, grant a limited extension to cure such deficiencies. Late or incomplete forms or proposals will result in the proposed project being eliminated from further consideration. All bids will be retained by Avista and will not be returned to project sponsors.

After completion of its initial evaluation process, Avista will notify those on a short list of bidders that their projects have been selected for further review and potential negotiation. Avista may meet with the short listed bidders. Bidders of those projects that are not selected will be so notified.

Avista may elect to negotiate certain aspects of the bidder's proposal. The bidder will be expected to remain prepared to deliver the services indicated in the proposal, subject to any changes mutually agreed to as part of the negotiation process. Failure to adhere to the original RFP will be justification for Avista to cease negotiations and to reject the proposal. Contracts may be subject to the approval of the IPUC and the WUTC, as appropriate.

Another key consideration is operating flexibility. Operating flexibility is represented by the project's compatibility with Avista's electric system and power supply. Timing of energy deliveries on a seasonal and daily basis is a measure of this criterion. Avista's ability to control project output levels is also important. These evaluation elements are further discussed in the Evaluation and Ranking sections under the Request for Energy Efficiency Resource Proposals and the Request for Power Supply Resources respectively

Avista retains sole discretion to determine which proposal best meets Avista's system requirements, and which will be selected for negotiation and further review. Avista will evaluate all proposals in the context of meeting overall least-cost objectives, which may take into account many factors, including but not limited to cost, risk, operating flexibility, diversity of supply, and any other relevant factors. Environmentally sound resources must meet all local, state, and federal agency requirements and, in the case of dedicated plant construction, the ability to handle local impact issues. The company will also be comparing bid proposals against its own programs and other proposed generation and energy efficiency resources.

Avista reserves the right to modify the RFP process to comply with any WUTC or IPUC orders, rules, regulations or guidelines.

If, upon review of the RFP, there are questions regarding completion of the RFP, please contact:

Avista Corp.
P.O. Box 3727
Spokane, WA 99220-3727

ATTN: 2000 Competitive Bid Proposal
c/o Doug Young
MSC-7

Schedule and Procedure

A. Milestone Schedule

August 14, 2000	RFP available to potential bidders
September 18, 2000	Submittal to Avista of resource proposals
September 22, 2000	Initial review completed by Avista

October 6, 2000	Determination of preliminary short list Notify project sponsors
October 20, 2000	Complete meetings with project sponsors
October 24, 2000	Selection of short list for negotiation
November 3, 2000	Final selection (RFP decision)

B. Submittal of Proposals. All project proposals must contain the information requested in this RFP and ten (10) copies must be submitted so as to be received by Avista no later than noon on September 18, 2000 at the following address:

Avista Corp.
E. 1411 Mission Avenue
Spokane, WA 99202

ATTN: 2000 Competitive Bid Proposal
c/o Doug Young
MSC-7

In accordance with WAC 480-107-070 (4), project proposals shall remain sealed until expiration of the solicitation period.

The preparation and submission of a project proposal will be at the expense of the project sponsor.

C. Modification or Withdrawal of Project Proposals

A sponsor of a project proposal may modify its project proposal by written request, provided that the request is received by Avista prior to September 18, 2000.

D. Initial Review of Project Proposals

Avista will perform an initial review of project proposals to determine if all required information has been provided. Avista expects to complete this initial review by September 22, 2000. Project sponsors who are not selected because of deficiencies in the response to the RFP will be so notified. Where such deficiencies are not material,

Avista may, at its option, grant an extension of seven (7) days to cure such deficiencies. Material deficiencies will disqualify a proposal from further consideration.

E. Confidentiality of Information

Avista may agree to keep confidential any document so designated by the participants in the bidding process. Inasmuch as project proposals are subject to examination by the WUTC pursuant to the WAC 480-107-070 (4), and by the IPUC, refusal to release confidential information to the WUTC or IPUC may adversely affect consideration of the project proposal.

Avista will take reasonable precautions and use reasonable efforts to protect confidential information, which is clearly identified as such on the page on which confidential material appears.

LIMITATIONS

THERE SHALL BE NO BINDING CONTRACT UNTIL AVISTA AND THE PROJECT DEVELOPER HAVE EXECUTED A FINAL WRITTEN PURCHASE AND SALE AGREEMENT. THIS RFP DOES NOT CONSTITUTE AN OFFER BY AVISTA, AND SUBMITTAL OF A PROJECT PROPOSAL SHALL NOT BE DEEMED AN ACCEPTANCE. AVISTA RETAINS THE RIGHT IN ITS SOLE DISCRETION TO REJECT ANY AND ALL PROJECT PROPOSALS AT ANY TIME BEFORE EXECUTION OF A FINAL WRITTEN PURCHASE AND SALE AGREEMENT AND TO REVISE THE MILESTONE SCHEDULE SET FORTH HEREIN. AGREEMENTS MAY BE SUBMITTED TO THE IPUC AND/OR WUTC FOR APPROVAL, AS APPROPRIATE.

Request for Energy Efficiency Resource Proposals

General Overview

Avista currently provides a variety of energy efficiency services to the Company's retail electric customers in all market segments. These services are currently funded through a special Tariff Rider approved by both the Washington and Idaho State Commissions. As the Company prepares to enter a period of potential energy deficiency, Avista is assessing the addition of energy efficiency activity, incremental to the current acquisition goal of 3 aMW per year, through a bidding process.

Avista's interest is in the acquisition of cost-effective energy efficiency and system capacity resources that positively contribute to our existing portfolio attributes. As such, the Company is seeking programs that incur the least amount of utility and total resource cost to acquire a desired level of electric efficiency or system capacity resources.

General Bidding Guidelines

All energy efficiency proposals shall, at a minimum, satisfy the requirements of WAC 480-107-030. A bidder must either be an Avista retail electric customer or a contractor proposing one or more projects at the site of an Avista retail electric customer. Project proposals must yield annual electricity savings of at least 2,190,000 kWh (250 aKW). The energy saving measures must be installed over a period of not more than three years. Savings from installed measures must persist for a period of at least five years. Project proposals selected under this RFP are not eligible for grants, loans, or other payments under any other Avista sponsored energy efficiency program during the life of the proposed project.

Bids may include electric efficiency projects or fuel conversion projects involving the replacement of electric end-use equipment with equipment using natural gas (natural gas

equipment must be at least 45 percent efficient). Bids may not include the substitution of alternative supplies of electricity or provide savings through the curtailment or cessation of end-uses. Electric energy savings must not result in significant reduction to the quality of end-use processes or products.

Avista will view some measures more favorably than others in the selection process. Unfavorable reviews would result from questionable assurance of savings, lack of savings persistence, degradation of savings, or concentration of measures at a single or small number of host facilities.

It is also required that all emissions credits accrued through electric energy savings resulting from the implementation of proposed energy efficiency measures become the sole property of Avista Corporation unless other arrangements are explicitly included in the final contract.

Proposal Contents

Following is a list of general topics that each proposal should address. Within each area are specific requests for information about each proposal. A written response to each specific request should be provided. If a request does not apply to a proposal, a written response is required which sets forth which requests are not applicable and a brief explanation as to why.

A. Description of Proposal

1. Describe the proposed energy efficiency measure(s) and the specific customer or customer type(s) and building type(s) where the measures will be located.
2. Provide an estimate of the projected annual electric energy savings and system capacity savings of the project when completed. Provide a detail of unit savings used to derive the total savings estimates, and the basis for those estimates. Provide a monthly distribution of those savings. If

system capacity savings are proposed, provide a description of what hour those savings are available or alternatively an hourly shape of savings. Provide an estimate of the monthly and annual load factors of savings for all measures.

3. Provide a description of dispatchability (or similar utility control), if any, of the project savings. This will probably apply only to measures incorporating system capacity savings.
4. Provide an estimate of the physical life and useful life each measure in the project proposal. Describe any maintenance and replacement requirements or savings of the measure(s).
5. Provide a timeline for project completion, with an estimate of savings achieved for each month until project completion.
6. Describe who is to own and operate the energy efficiency or system capacity efficiency measure(s) after they are installed.
7. List and describe who is to install the measure(s), including any installation subcontractors.
8. To the extent possible, describe and support any reasons that the bid proposal may better benefit Avista and its customers than the Company's existing energy efficiency programs if that proposal is partially or entirely mutually exclusive with an existing program.

B. Price and Payment Structure. The price bid, the requested pricing configuration, and terms of the proposed services are subject to negotiation.

1. Provide a detailed description of the price of the proposal, including amount per unit and timing of payments. Bid price can be based upon annual payments, or initial payment per kWh or kW saved, or initial payment per measure installed.
2. Detail any portion of the payment to be based on measured performance. Detail any portion of the payment to be based on other criteria. Performance-based pricing structures are preferred but not rigidly required.

3. Describe the proposed payment plan, including when payment for savings will be made, the conditions that must be met before payment is made, and how payments may be adjusted following any verification of savings procedures.
4. Provide an estimate and description of fees, shared savings arrangements, or any other contribution the customer or third party will be obligated to pay for the installation of any portion of the proposed measure(s).
5. Provide a calculation showing the utility costs of the proposal.

C. Savings Verification Plan.

1. Describe the procedures that will be used to estimate and measure savings from the installed measures. For estimates that are to be made, describe how they are derived and the assumptions and sources used to develop the estimates. For savings that are to be measured, describe the proposed measurement procedures. Provide sufficient detail on the measurement procedures, including the type of measurement (i.e., billing analysis or end-use metering) and the participants included in the measurement. The savings verification plan should address both first year annual savings and savings persistent over the proposed life of the measure. Describe any plans to verify estimated savings. Describe any procedures that will be in place to measure the persistence of the energy savings.
2. Describe Avista's role in the proposed verification plans. Describe any information, data, or support that Avista will need to provide to the verification plan.
3. Describe the timeline for savings verification. Specifically describe the links between measure installation, verification of savings and payment.
4. Provide a proposal for assessing the level of free-ridership resulting from the proposal. Free-riders are generally defined as program participants who would have adopted the measure(s) in the absence of the proposed program.

D. Marketing and Customer Service Plan.

1. Provide a description of the marketing plan that will be used to recruit participants, if appropriate. Describe how customers will be contacted and how eligibility for participation will be determined.
2. Describe how your proposal is designed to minimize the level of free-ridership. This may include a description of how participants will be recruited and the expected simple payback for participants with and without financial incentives. (Simple payback is to be calculated as the participant's cost divided by the annual energy bill savings.)
3. Describe how participant complaints will be addressed.
4. Describe any general marketing assistance the bidder expects Avista to provide. This may include customer lists, customer billing records, letters of introduction, or support by the Company's customer service representatives.
5. Describe written or implied warranties that will be provided to customers regarding quality of materials and installation.
6. Any bidders currently operating programs will be required to provide Avista with information on participants, measures installed, estimated energy savings, system capacity impact, and participant costs. Describe the intention to track and provide that information to Avista.
7. List complaints received from participants regarding the conduct of past energy or capacity efficiency programs by the bidder and the disposition of each complaint.

E. Financial Capability

1. Provide a description of plans for financing the energy efficiency project(s).
2. If your proposal requires liquidated damages, describe the proposed security arrangements (i.e., bank letter of credit, payment bond, corporate guarantee, or other security).

3. Be prepared to provide, if the proposal is selected for negotiation, a demonstration of the ability to obtain a level of insurance, such as general business and liability insurance, sufficient to cover major project contingencies.

F. General Qualifications

1. Please be prepared to provide three or more references from the last five jobs where the bidder has performed similar services to those proposed to Avista if the proposal is selected for negotiation. These references can be a contact person at another utility to whom the bidder has provided services, or electric customers for whom the bidder has provided energy efficiency services, preferably similar to those included in the bidder's proposal. Provide telephone numbers for these references.
2. Provide a general description of the your organizations background and experience in projects similar to your proposal.
3. Be prepared to list and describe, if the proposal is selected for negotiation, any licenses that you or your subcontractors have or will be required to obtain to perform the type of work described in your proposal.
4. Be prepared to describe, if the proposal is selected for negotiation, how your proposal complies with all applicable codes, permits and licenses legally required for the measure installations proposed. A list of the necessary permits will also be required during negotiation.
5. Provide form of business classification (i.e., sole proprietorship, partnership, or corporation).
6. Be prepared to list, if the proposal is selected for negotiation, all affiliated companies, including holding companies, subsidiaries, and predecessor companies presently or in the past engaged in delivering the types of services included in the proposal.
7. Provide a list of prior organizations for which key management team members have worked if such organizations have provided services similar to those in the proposal.

8. Be prepared to list all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been engaged related to the types of services proposed if the proposal is selected for negotiation. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.
9. Detail the disposal of waste to be removed from customer facilities as part of energy efficiency projects, including the disposal of toxic and contaminated waste. Describe any recycling strategies to be incorporated into disposing of removed materials from the project.
10. Detail specific environmental aspects of the project, including any planned utilization of recycled materials in equipment supplied to the project.

Evaluation and Ranking of Energy Efficiency Proposals

All energy efficiency and system capacity proposals will be evaluated and ranked against the other proposals submitted. The review and possible selection of projects will be based on which proposal(s) provide the optimum value to Avista's customers. Proposals will first be screened to ensure that they meet required criteria as stated in this RFP and have completed the "Checklist For Energy Efficiency and System Capacity Resources".

A preliminary evaluation will follow the initial screening to narrow the list. The evaluation will be based upon both price and non-price criteria. The pricing evaluation will consider measure persistence, timing and flexibility of capacity delivery, degradation of savings, program free-ridership and market transformation. Evaluation of non-price factors will include, but will not be limited to, the economic value to participating customers and the compatibility of the program with Avista's overall energy efficiency portfolio.

Next, a detailed evaluation of selected proposals will take place and could include meetings with bidders. Following the detailed evaluation will be the selection of proposals for negotiation. Negotiation does not guarantee an award of a written contract.

Due to the individual and unique nature of each bid, evaluation and ranking will include the balancing the various impacts of the criteria bid. The six categories that will be used in the proposal ranking will be the description of proposal, price and payment structure, savings verification plan, marketing and customer service plan, financial capability, and general qualifications and references.

If any proposal receives an unacceptable rating in any category, Avista may, at its sole discretion, eliminate that proposal from further review. However Avista, at the discretion of reviewers, may request a bidder to correct minor deficiencies in order for the bid to receive an overall acceptable rating.

CHECK LIST FOR ENERGY EFFICIENCY AND SYSTEM CAPACITY RESOURCES

To be completed for all bid proposals. Please check in the space provided if the applicable exhibit is attached.

GENERAL INFORMATION
Project Sponsor's Name:
Address:
Phone Number:

PROJECT INFORMATION
Project Location:
Annual Energy Capability (MWh):
Term of Sale:
Date of First Installation:

DESCRIPTION OF PROPOSAL		
Description of Measures	A.1.	_____
Estimated Savings	A.2.	_____
Physical & Useful Life	A.3.	_____
Dispatchability	A.4.	_____
Timeline	A.5.	_____
Owner & Operator	A.6.	_____
Subcontractors	A.7.	_____
Why Use Your Proposal	A.8.	_____

PRICE AND PAYMENT STRUCTURE		
Description of Price	B.1.	_____
Measured Performance	B.2.	_____
Payment Plan	B.3.	_____
Fee or Shared Savings	B.4.	_____
Utility Cost	B.5.	_____

SAVINGS VERIFICATION PLAN		
Description of Plan	C.1.	_____
Avista's Role	C.2.	_____
Timeline	C.3.	_____
Free-ridership	C.4.	_____

MARKETING AND CUSTOMER SERVICE PLAN		
Description of Marketing Plan	D.1.	_____
Free Riders	D.2.	_____
Complaints Procedure	D.3.	_____
Avista's Role	D.4.	_____
Warranties	D.5.	_____
Data Gathering	D.6.	_____
List of Complaints	D.7.	_____

FINANCIAL CAPABILITY		
Description of Plan	E.1.	_____
Liquidated Damages	E.2.	_____
Insurance	E.3.	_____

GENERAL QUALIFICATIONS		
References	F.1.	_____
Experience	F.2.	_____

Licenses	F.3.	_____
Codes and Permits	F.4.	_____
Business Classification	F.5.	_____
Affiliated Companies	F.6.	_____
Key Individuals	F.7.	_____
Lawsuits	F.8.	_____
Waste Disposal	F.9.	_____
Environmental Aspects	F.10.	_____

Request for Power Supply Resources

General Discussion

Avista has identified the need for 300 MW of capacity and 300 MW of average energy. Resource availability in the year 2004 would fit Avista's requirements best. However, Avista does have significant resource needs in advance of this time frame and will evaluate proposals with different starting dates. Each proposal shall set forth a term. However, Avista is interested in long-term arrangements that will meet resource requirements of twenty years or more. Avista desires to acquire operating flexibility in this power supply. Therefore, additional value will be placed on power supplies with the following attributes:

- Firm delivery backed by a generating resource or a composite of resources preferably within the Northwest Region.
- Price capped to emulate the cost from a generating resource.
- Curtailment capability to allow Avista an opportunity to stop deliveries. If deliveries from a project may be curtained at Avista's option, Avista would have the opportunity to purchase power from the wholesale electric market when the market price is less expensive than the firm purchased power supply.
- The ability to quickly make changes in delivery (ramp-up and ramp-down) in order to follow variable load obligations.

Avista's objective is to find the most economical option to fulfill this resource requirement. All bids will be evaluated based on their cost, flexibility service provided and overall usefulness to Avista. Avista invites proposals on the various options described under "Bids Requested". Avista has listed a separate option under "Bids Requested" in order encourage bids for cost-effective renewable resource proposals. Avista also welcomes your ideas that you may feel better meet the objective of this RFP.

Point of Delivery

Specify the point of delivery for each product offered. If the point of delivery is at a point other than Avista's system, Avista will add transmission costs to deliver the product to its system. If Avista is not the holder of the contract for third party transmission, Avista will place additional value on options to move the delivery point within the Northwest Region on a non-firm or as available firm basis. However, Avista prefers to hold the contract for third party transmission, if required to deliver the power. Direct delivery to Avista's system can be made at the following points:

1. Wanapum – interconnection with multiple parties at mid-Columbia
2. Westside - BPA interconnection
3. Bell – BPA interconnection
4. Hatwai – BPA interconnection
5. Hot Springs – BPA and Montana interconnection
6. Lolo – Idaho interconnection
7. Other points will be considered

For purposes of responding to this RFP, assume that adequate transmission capacity exists at Avista's points of delivery listed above. Transmission limitations (if any) will be considered in subsequent steps of the selection process.

General Qualifications List

A. Please provide three or more references from the last five projects where the bidder, or its affiliates, if appropriate, have implemented a power supply proposal similar to those proposed to Avista. These references can be a contact person with whom the bidder has transacted business. Provide telephone numbers for these references.

B. Provide a general description of the bidder's background and experience in power supply proposals similar to its proposal.

C. Provide form of business classification (i.e., sole proprietorship, partnership, or corporation).

D. List all affiliated companies, including holding companies, subsidiaries, and predecessor companies presently or in the past engaged in developing and/or implementing power supply proposals.

E. Provide a list of prior organizations for which key management team members have worked if such organizations have developed and/or implemented power supply proposals.

F. List all lawsuits, regulatory proceedings, or arbitration in which the bidder or its affiliates or predecessors have been engaged related to the types of power supply proposals proposed. Identify the parties involved in such lawsuits, proceedings, or arbitration, and the final resolution or present status of such matters.

G. Detail specific environmental aspects of the power supply proposal.

H. Provide a statement of responding companies financial status and ability to obtain financing.

I. Provide a list of any current credit issues raised by rating agencies, banks, or accounting firms. Provide credit rating if available.

Evaluation and Ranking of Power Supply Proposals

All power supply proposals will be evaluated and ranked against the other power supply proposals submitted. The review and possible selection of power supply will be based on which proposals can provide optimum value to Avista's customers.

Proposals will first be screened to ensure they meet required criteria as stated in this RFP and have completed the applicable sections of the "Checklist For Power Supply Resources". General Qualifications must be provided as outlined above plus the project specific information requested for each proposal submitted under the respective section of "Bids Requested". A preliminary evaluation will follow the initial screening to narrow

the list. Evaluation will be based upon both price and non-price criteria. Renewable Energy projects will receive a 10% credit on price to account for reduced air quality impact and other environmental impacts. The evaluation will be split into the following three principle areas for evaluation: Electric Power Characteristics including ability of the project to meet size, dispatchability, fuel supply, timeline and other characteristics of Avista's need described in this RFP and in its "1997 Integrated Resource Plan Update" and the ability of the operator to meet construction and operational commitments; Financial/ Price Characteristics including demonstrated adequacy of financial capability to construct and maintain projects; Social/Environmental Characteristics including using reasonably current available environmental mitigation technology and ability to meet local, state, and federal agency requirements and, in the case of dedicated plant construction, the ability to handle local impact issues. Next, a detailed evaluation of selected proposals will take place. Following the detailed evaluation will be the selection of proposals for negotiation. Negotiation does not guarantee an award of a written contract.

Due to the individual and unique nature of each bid, the evaluation and ranking will include balancing the various impacts of the criteria bid including but not limited to price and payment structure, financial capability, and general qualifications and references.

If any proposal receives an unacceptable rating in any category Avista may, at its sole discretion, eliminate that proposal from further review. However Avista, at the discretion of reviewers, may request a bidder to correct minor deficiencies in order for the bid to receive an overall acceptable rating.

Bids Requested

Avista will consider all power supply proposals. In particular it is interested in receiving proposals of the types described below:

I. Capacity & Energy Purchase.

Avista will evaluate a purchase of a firm capacity and energy product. A power sale to Avista should be a firm product with interruption rights only for force-majeure conditions. This product may be purchased in increments that total up to 300 MW of capacity and energy.

Items to include in bid relating to "Capacity & Energy Purchase":

1. The source of the energy supply, for example, a generating plant dedicated solely to this sale, a composite or system of generating plants, the market.
2. Supplier curtailment rights.
3. Avista's curtailment rights, for example; right to purchase lower cost alternatives, to follow load reductions.
4. Flexibility that allows Avista to make quick changes in delivery to follow variable load obligations.
5. Control area of origin.

Sale scenarios may include:

A.	January 1, 2004 – December 31, 2023	300 MW all hours - flat;
B.	January 1, 2004 – December 31, 2023	300 MW, but Avista has dispatch rights.

II. Qualifying Facilities with a generating capacity of less than one megawatt.

Sponsors of Qualifying Facilities under the Public Utilities Regulatory Policies Act of 1978 (PURPA) with a generating capacity of less than one (1) MW of installed capacity are eligible to enter into long-run or short-run (energy only) contracts without submitting a bid pursuant to the RFP. Sponsors should contact Avista to obtain a copy of Avista's long-run or short-run prototype contracts.

III. Qualifying Facilities with a generating capacity of more than one megawatt.

Sponsors of Qualifying Facilities under PURPA with a generating capacity of more than one megawatt are eligible to enter into short-run contracts (energy only) without submitting a bid pursuant to the RFP. Sponsors should contact Avista to obtain a copy of Avista's short-run prototype contract. Sponsors of Qualifying Facilities under PURPA with a generating capacity of more than one megawatt that desire to enter into long-run contracts are invited to submit bids in accordance with this RFP.

IV. Renewable Power Supplies.

Renewable project developers are invited to make bids from competitive renewable resource projects. Avista is looking for competitive proven technology based proposals. Avista would like to evaluate both proposals for power delivery from renewable power projects and proposals for Avista ownership of a portion of or all of a renewable power project. Bidders should provide at a minimum, the following information about their project.

A. Description of Proposal

1. Describe the proposed specific renewable resource project. Describe the nature and characteristics of that project including location and power interconnection and transmission arrangements. Provide information regarding project ownership and operation.
2. Provide an estimate of the projected capacity and energy from the project. Provide information regarding when specific amounts of capacity and energy will be available. Provide a monthly distribution of energy production. If capacity will be provided, provide a description of what hours that capacity will be available firm or alternatively an hourly shape of available firm capacity. Provide an estimate of the monthly and annual plant factors.
3. Provide a description of dispatchability (or similar utility control), if any, of the project energy output. This will probably apply only to projects with capacity.

4. Describe when project power will be made available including any project timelines that may be applicable. Describe any variables that could affect those timelines.

V. Power Plant Site.

A. Combined Cycle Combustion Turbine

Avista would like to evaluate the construction of a 260 MW (nominal) natural gas fired Combined Cycle Combustion Turbine power plant. Avista would like to have parties bid sites for this construction in the Northwest region. A site offer should include all electric transmission necessary to connect the plant with the main power grid and all natural gas transmission necessary to interconnect the plant with interstate natural gas transmission facilities. In addition, information regarding each of the following must be included in the proposal:

1. Water supply characteristics, including: source; quality; and quantity.
2. Waste disposal characteristics, including: requirements; and treatment facility.
3. Work force characteristics, including:
   a) where it originates from to support construction;
   b) where it originates from to support operation;
   c) community infrastructure;
   d) what the surrounding community offers to support construction; and operation.
4. Community support, including political environment.
5. Transportation infrastructure, including, highways, railroads and airports.
6. Permits in General. The proposed site should have a complete description and listing of all permits acquired, pending and permits that must be acquired before the 260 MW (nominal) combined cycle combustion turbine can be built.

7. Air Permit. The air permit should be included with the RFP or described in detail. An itemized listing of the conditions under which the project is subject to operate must be attached. This assumes construction of a combined cycle combustion turbine with a output of 260 MW (nominal). The list must include but not be limited to the maximum each pollutant can emit by hour, year, etc.
8. A legal description of the proposed site.
9. Documentation of support for the project from local residents, state, local and federal agencies, and local political groups.
10. Documentation describing all opposition to the proposed development whether it is formal or informal.
11. Land and resource use considerations including, existing land use, cultural resources, earth resources and critical habitat.
12. All other attributes your site possesses that would make siting a combined cycle combustion turbine a positive decision.
13. Demonstration that the combined cycle combustion turbine project is licensable and operational under applicable site constraints.

B. Simple Cycle Combustion Turbine

Avista would like to evaluate the construction of up to 172 MW (nominal) of natural gas fired Simple Cycle Combustion Turbine power plants. Avista would like to have parties bid sites for this construction in the Northwest region. A site offer should include all electric transmission necessary to connect the plant with the main power grid and all natural gas transmission necessary to interconnect the plant with interstate natural gas transmission facilities. In addition, information regarding each of the following must be included in the proposal:

1. Water supply characteristics, including: source; quality; and quantity.
2. Waste disposal characteristics, including: requirements; and treatment facility.

3. Work force characteristics, including:
   a) where it originates from to support construction;
   b) where it originates from to support operation;
   c) community infrastructure;
   d) what the surrounding community offers to support construction; and operation.
4. Community support, including political environment.
5. Transportation infrastructure, including, highways, railroads and airports.
6. Permits in General. The proposed site should have a complete description and listing of all permits acquired or pending and permits that must be acquired before the 172 MW (nominal) simple cycle combustion turbines can be built.
7. Air Permits. The air permit should be included with the RFP or described in detail. An itemized listing of the conditions under which the project is subject to operate must be attached, this assumes construction of simple cycle combustion turbines with a output of 172 MW (nominal) must be included. The list must include but not be limited to the maximum each pollutant can emit by hour, year, etc.
8. A legal description of the proposed site.
9. Documentation of support for the project from local residents, state, local and federal agencies, and local political groups.
10. Documentation describing all opposition to the proposed development.
11. Land and resource use considerations including, existing land use, cultural resources, earth resources and critical habitat.
12. All other attributes your site possesses that would make siting a simple combustion turbine a positive decision.
13. Demonstration that the ~~combined~~ cycle combustion turbine project is licensable and operational under applicable site constraints.

VI. Turnkey Power Plants On Avista's Site.

A. Combined Cycle Combustion Turbine

Avista would like to evaluate the purchase of a turnkey 260 MW (nominal) natural gas fired Combined Cycle Combustion Turbine power plant located on a site provided by Avista. Please describe any variables that would change the ultimate cost to Avista which are dependent on the location of the plant. (Sales tax is an example.)

1. General Description. The following is a general description of the facility that is to be built and does not intend to describe all materials, equipment, facilities and manpower necessary for a completed facility to operate as described:
   - 1.1 One advanced technology combustion turbine and generator (CTG) based upon GE 7FA or equal. Unit should have inlet-cooling capabilities.
   - 1.2 One heat recovery steam generator (HRSG). Unit should have duct firing capabilities.
   - 1.3 One steam turbine and generator (STG).
   - 1.4 Associated balance of plant equipment.
   - 1.5 CTG will have only natural gas capabilities.
   - 1.6 The gas turbine will be equipped with a dry lo Nox combustion system.
     - a) Nox limits will be 9 ppm at 15% O2 on natural gas for the CTG
     - b) CO limits will be 9 ppm at 15% O2 on Natural gas for the CTG
   - 1.7 SCR will be added if required to meet additional permit requirements for Nox emissions.
   - 1.8 CO catalyst will be added if required to meet additional permit requirements for CO emissions.
   - 1.9 The CTG will be coupled to a synchronous hydrogen cooled or TEWAC (totally enclosed water to air cooled) generator.
   - 1.10 Plant shall also include a control system, inlet air system, lubrication oil system, hydraulic oil system and any other miscellaneous equipment necessary to support its operation.

1.11 Exhaust gas from the CTG shall be ducted into the HRSG to effectively recover the waste heat.

1.12 Transformers to step up the generation to 230 kv (configuration to be evaluated).

1.13 Other supporting equipment to provide safe and efficient operation shall include but not be limited to:

a) A demin system to meet the plant requirements

b) Cranes to perform required maintenance

c) Buildings to protect equipment

d) A DCS

e) Main surface condenser

f) Mechanical draft cooling tower

g) Boiler feed water pumps

h) Generator circuit breakers

i) Power centers

j) Motor control centers

k) Spare parts

2. Specifics of Site. It may be assumed that Avista will provide electric transmission to the property line and gas transmission to the property line. Also, it may be assumed that Avista will provide a suitable piece of property. The following site conditions will be assumed for the installation and design of a combined cycle combustion turbine on Avista's site:

Soil bearing	4000 psf
Wind velocity	100 mph
Snow load	50 psf
Rainfall in a 24 hour period	1 inch
Maximum temperature	plus 100 degrees F
Minimum temperature	minus 30 degrees F
Approximate site elevation	2000 feet above sea level
Approximate humidity	60%

3. This power plant should have inlet cooling and duct firing capabilities. Avista would plan to start and stop this plant 50 to 100 times per year. The majority of these starts would be considered hot starts, since the plant may be run for 16 hours during the day and shutdown to no load for 8 hours each night. The duct fired option may be used up to 8000 hours per year. Avista also prefers to have the ability to operate this plant on load control to follow variable load obligations. Avista will require input and review during design and construction of the project. Items of importance will include design and construction timelines, online date, heat rate curves, peak output, ramp rates, var capability, maintenance schedules and costs, recommended operation and maintenance staff, spare parts inventory and cost, type and availability of equipment and training programs. The design of the plant from an aesthetic point of view will be considered.

4. Sponsors should describe the number and qualifications of employees required to operate proposed facilities.

B. Simple Cycle Combustion Turbine

Avista would like to evaluate the purchase of turnkey natural gas fired Simple Cycle Combustion Turbine power plants of up to 172 MW sited on a site provided by Avista. The type and number of simple cycle combustion turbines will be evaluated. Please describe any variables that would change the ultimate cost to Avista which are dependent on the location of the plant. (Sales tax is an example.)

1. General Description. The following is a general description of the facility that is to be built and does not intend to describe all materials, equipment and facilities necessary for a completed facility to operate as described:

1.1 Advanced technology combustion turbines and generators (CTG).

1.2 Associated balance of plant equipment.

1.3 CTG will have only natural gas capabilities.

1.4 The gas turbine will be equipped with a dry lo Nox combustion system

a) Nox limits will be 25 ppm at 15% O2 on natural gas for the CTG

b) CO limits will be 9 ppm at 15% O2 on Natural gas for the CTG

1.5 SCR or equal will be added if required to meet additional permit requirements for Nox emissions.

1.6 CO catalyst will be added if required to meet additional permit requirements for CO emissions.

1.7 The CTG will be coupled to a generator (type to be evaluated).

1.8 Plant shall also include a control system, inlet air system, lubrication oil system, hydraulic oil system and any other miscellaneous equipment necessary to support its operation.

1.9 Transformers to step up the generation (configuration to be evaluated).

1.10 Other supporting equipment to provide safe and efficient operation shall include but not be limited to:

a) A demin system to meet the plant requirements if required

b) Cranes to perform required maintenance

c) Buildings to protect equipment

d) A DCS

e) Generator circuit breakers

f) Power centers

g) Motor control centers

h) Spare parts

2. Specifics of Site. It may be assumed that Avista will provide electric transmission to the property line and gas transmission to the property line. Also, it may be assumed that Avista will provide a suitable piece of property. The following site conditions will be assumed for the installation and design of a simple cycle combustion turbine on Avista's site:

Soil bearing	4000 psf
Wind velocity	100 mph
Snow load	50 psf
Rainfall in a 24 hour period	1 inch
Maximum temperature	plus 100 degrees F
Minimum temperature	minus 30 degrees F
Approximate site elevation	2000 feet above sea level
Approximate humidity	60%

3. This power plant should have inlet cooling and duct firing capabilities. Avista may plan to start and stop this plant 200 times per year. The majority of these starts would be after a 16 hour run with a 4 to 8 hour cool-down period before starting again. Avista also prefers to have the ability to operate this plant on load control to follow variable load obligations. Avista will require input and review during design and construction of the project. Items of importance will include design and construction timelines, online date, heat rate curves, peak output, ramp rates, var capability, maintenance schedules and costs, recommended operation and maintenance staff, spare parts inventory and cost, type and availability of equipment and training programs. The design of the plant from an aesthetic point of view will be considered.

4. Sponsors should describe the number and qualification of employees required to operate proposed facilities.

VII. Turnkey Power Plant Including Site.

A. Combined Cycle Combustion Turbine

Avista would like to evaluate the purchase of a turnkey 260 MW (nominal) Combined Cycle Combustion Turbine power plant including the site. The proposal should describe

the general site characteristics as set forth in Section ***IV,*** above. The power plant should have the same general characteristics as set forth in Section ***V***.A, above.

B. Simple Cycle Combustion Turbine

Avista will evaluate the purchase of turnkey Simple Cycle Combustion Turbine power plants including the site for up to 172 MW (nominal). The proposal should describe the general site characteristics as set forth in Section ***IV,*** above. The power plant should have the same general characteristics as set forth in Section ***V***.B, above.

CHECK LIST FOR POWER SUPPLY RESOURCES

To be completed for all bid proposals. Please check in the space provided if the applicable exhibit is attached.

GENERAL INFORMATION

Project Sponsor's Name:
Address:
Phone Number:

PROJECT INFORMATION

Project Location:
Nameplate Rating (MW):
Annual Energy Capability (MWh):
Term of Sale:
Date of First Delivery (Commercial Operation):
Major Fuel Type:
Ownership:

DESCRIPTION OF PROPOSAL

I. Capacity & Energy Purchase
- A.1. _____
- A.2. _____
- A.3. _____
- A.4. _____
- A.5. _____
- B.1. _____
- B.2. _____
- B.3. _____
- B.4. _____
- B.5. _____

II. Qualifying Facilities with a generating capacity of less than one megawatt
_____

III. Qualifying Facilities with a generating capacity of more than one megawatt
_____

IV. Renewable Power Supplies
- A.1. _____
- A.2. _____
- A.3. _____
- A.4. _____

V. Power Plant Including Site
- A. Combined Cycle Combustion Turbine
  - A.1. _____
  - A.2. _____
  - A.3. _____
  - A.4. _____
  - A.5. _____
  - A.6. _____
  - A.7. _____
  - A.8. _____
  - A.9. _____
  - A.10. _____
  - A.11. _____
  - A.12. _____
  - A.13. _____
- B. Simple Cycle Combustion Turbine

B.1. _____
B.2. _____
B.3. _____
B.4. _____
B.5. _____
B.6. _____
B.7. _____
B.8. _____
B.9. _____
B.10. _____
B.11. _____
B.12. _____
B.13. _____

VI. Turnkey Power Plants On Avista's Site

A. Combined Cycle Combustion Turbine

A.1.1. _____
A.1.2. _____
A.1.3. _____
A.1.4. _____
A.1.5. _____
A.1.6. _____
A.1.7. _____
A.1.8. _____
A.1.9. _____
A.1.10. _____
A.1.11. _____
A.1.12. _____
A.1.13. _____

A.2. _____
A.3. _____
A.4. _____

B. Simple Cycle Combustion Turbine

B.1.1. _____
B.1.2. _____
B.1.3. _____
B.1.4. _____
B.1.5. _____
B.1.6. _____
B.1.7. _____
B.1.8. _____
B.1.9. _____
B.1.10. _____

B.2. _____
B.3. _____
B.4. _____

VII. Turnkey Power Plant Including Site

A. Combined Cycle Combustion Turbine

A.1. Same as Section IV. _____

A.2. Same as Section V.A. _____

B. Simple Cycle Combustion Turbine

B.1. Same as Section IV. _____

B.2. Same as Section V.B. _____

APPENDIX A

WUTC BIDDING RULE

Bidders participating in Avista's 2000 RFP that would like a copy of the WUTC bidding rule WAC 480-107 can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

APPENDIX B

MODEL CONTRACTS

The following 1994 model contracts are included in this appendix

1. DEMAND SIDE MANAGEMENT PURCHASE AGREEMENT
2. FIRM POWER PURCHASE AGREEMENT
3. PARALLEL OPERATING AND POWER PURCHASE AND SALE AGREEMENT

These model contracts provide a basis for negotiation of a purchase agreement with Avista Corporation. Bidders should expect that a final agreement will have many changes in terms and conditions through the negotiation process.

Bidders participating in Avista's 2000 RFP that would like a copy of these model contracts can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

APPENDIX C

RETAIL TARIFFS

Bidders participating in Avista's 2000 RFP that would like a copy of Avista's retail service tariffs can receive a copy by contacting Doug Young at (509) 495-4521 at Avista's general office in Spokane, Washington.

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-7)

RFP Bid Analysis Review

Avista Corporation
Spokane, Washington

December 2000

Exhibit No. _____(RJL7)
Docket No. UE-01_____

December 7, 2000

R·W·BECK

Mr. Robert J. Lafferty
Manager, Electric Resources
Avista Corporation
1411 East Mission, MSC-7
Spokane, Washington 99220-3727

Dear Mr. Lafferty:

Subject: **Review of Avista Corporation's RFP Bid Analysis**

R. W. Beck, Inc., was retained by Avista Corporation (Avista) in October 2000 to conduct an independent review of the methodology and assumptions used by Avista to review the bids received from its August 2000 Request for Proposals titled "Evaluation of Resources from Electric Energy Efficiency and/or Power Supply Resources." The goal of R. W. Beck's independent review was to assure that the economic analysis of the alternative resource bids was conducted in a fair, reasonable, and appropriate manner. Avista's analysis of certain other factors (such as transmission accessibility, environmental factors, etc.) was not reviewed. This report summarizes our review of Avista's analysis conducted through November 28, 2000. Changed conditions occurring after such date were not considered in our review.

BACKGROUND

Avista Utilities, a division of Avista Corporation, is a private investor-owned electric utility with headquarters in Spokane, Washington. In August 2000, Avista issued a Request for Proposals (RFP) seeking potential resources to meet its system requirements of energy and capacity. According to the RFP:

> *"... The company has identified a power need of approximately 300 MW of both capacity and corresponding energy. Resource availability in the year 2004 would fit Avista's requirements best.*
>
> *"... The goal of the 2000 RFP will be to identify low cost and environmentally sound resource options that best satisfy Avista's resource needs."*

In response to the RFP, Avista received numerous proposals from resource sponsors (the bids). As part of the bid review process, Avista attempted to calculate the economic and financial benefit of each of the bids using Avista-developed methodology and assumptions. Avista also studied the potential benefits and costs of enhancing an existing generation facility, which we will refer to as the "self-build option" in this report.

To assure the fairness and reasonabless of their economic analysis, Avista retained R. W. Beck to conduct an independent review of their methodology and assumptions; to

assure that significant economic risks, benefits, and costs were identified; and to make note of, and suggest corrections for, any deficiencies found. R. W. Beck has completed an independent review of the economic analysis of the bids and our findings and conclusions are presented in this report.

SCOPE OF SERVICES

Avista identified the following tasks as part of the scope of services for a third-party review of Avista's evaluation methodology and input assumptions.

1. Review the *Prosym*™ dispatch model inputs and assumptions on six to eight representative bids. Make recommendations for any modifications aimed at achieving Avista's RFP goals.
2. Review the Avista economic model inputs and assumptions on six to eight representative bids. Make recommendations for any modifications aimed at achieving Avista's RFP goals.
3. Be available to discuss with Avista representatives the recommended modifications under Tasks 1 and 2 above.
4. Prepare a final letter report summarizing recommended modifications for dispatch model and economic model inputs and assumptions aimed at achieving Avista's RFP goals.
5. Present a review of the recommendations for analysis inputs and assumptions to Avista management, staff, and commission staff from Washington and Idaho in Spokane, Washington.

This letter report constitutes completion of Task 4 above. The Task 5 presentation was provided on November 29, 2000 at Avista's headquarters building in Spokane.

INFORMATION PROVIDED AND REVIEWED

Avista provided several reports, analyses, and other information for use in the independent review. In addition, numerous group discussions were held with Avista staff for clarification and further insight. The information reviewed is summarized as follows:

1. August 2000 RFP from Avista.
2. "Evaluation Guidance for Electric RFP Bid Proposals" from Avista.
3. "WSCC Regional Electricity Market Price Forecast 2001-2012, September 2000" prepared by Henwood Energy Services, Inc., for Avista.

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4. Submitted proposals from six bidding resource sponsors, including:
   a. Calpine Corporation
   b. Enron North America Corporation
   c. Newport Northwest, LLC
   d. Pacific Winds Inc.
   e. Regional Power Inc.
   f. Williams Energy Marketing & Trading Company
5. *Prosym*™ model input files representing the Avista system for each of seven proposed resource options and the enhancement of the existing Rathdrum generation facility (self-build option). The eight various resource bids/options given to R. W. Beck for review were identified by Avista as follows:
   a. Calpine
   b. Enron Monthly Toll
   c. Newport Northwest
   d. Pacific Winds
   e. Rathdrum
   f. Regional Power
   g. Williams Energy Flat Purchase
   h. Williams Energy Toll
6. *Prosym*™ model results contained in electronic spreadsheets for each of the eight resource options.
7. Economic analysis spreadsheets for each of the eight resource options, used to calculate each resource option's projected revenues, costs, and net project benefit to the Avista system.

OVERVIEW OF AVISTA'S APPROACH, METHODOLOGY, AND ASSUMPTIONS

Avista used the production costing and market simulation model, *Prosym*™, to determine certain costs and benefits of each of the bids as well as the self-build option. *Prosym*™ is generally considered within the electricity industry to be an acceptable model for such purposes, capable of modeling both expansive, interconnected markets and smaller utility systems in detail and with a high degree of accuracy. Avista staff created a detailed model of Avista's system, representing on-peak and off-peak loads, hydroelectric and thermal generating resources, contractual sales and purchases, and spot-market sales and purchases.

The spot-market sales and purchase prices used in the model were based on market price forecasts provided by R. W. Beck staff. A price forecast was provided for a base case scenario and various sensitivity scenarios, developed primarily to provide a range of prices and to illustrate the change in market prices resulting from a change in key input assumptions, such as a change in natural gas prices. A detailed discussion of the market prices used in the analysis is provided below under the heading "Market Price Forecast."

For each pricing scenario (base case and sensitivities) the model was run once based on existing resources, and then a second time with each resource proposal individually added to the model. The difference in Avista's total system cost between the various model simulations was used to determine which projects are most beneficial or most costly. Because the results from model simulations are fundamental to Avista's economic decisions, the accuracy and completeness of input variables is very important.

Avista's economic analysis of the bids and the self-build option was primarily presented in the form of a spreadsheet model that compared Avista's total system cost with and without each of the resource options and the potential cost and revenue requirements of each of the proposed resource alternatives. These economic analysis spreadsheets provided detailed data for each of the resource options for the total Avista system for years 2001 to 2025. Included in the economic analysis spreadsheets are:

- Financial assumptions

  Sample of Avista's most critical assumptions:

State Income Tax Rate	0.00% (None)
Federal Income Tax Rate	35.00%
Discount Factor	7.77%
Tax Life (years)	20
Book Life (years)	20
Property Tax Rate	1.4099%
Levelize Period (years)	20

  Cost of Capital:

Capital Source	Percent of Total	Percent Rate	Weighted Average	After-tax Weighted Average
Debt	49.00%	7.36%	3.61%	2.35%
Preferred Stock	9.00%	8.11%	0.73%	0.73%
Common Stock	42.00%	11.16%	4.69%	4.69%
	100.00%		9.03%	7.77%

- Projections of annual energy produced from the various resource options to supply Avista's system, calculated through the *Prosym*™ simulation model where applicable.

- Projected resource costs—including any applicable fuel costs, fuel transportation costs, variable operations and maintenance costs (variable O&M), transmission costs, and fixed costs. These costs, if not explicitly set forth as an exact amount in the bids, are projected using the *Prosym*™ simulation model, where appropriate.
- Projected operating margin—defined by Avista as the added benefit or cost savings to the total system cost when the resource is included as compared with the Avista base case (the case where no resource options are included and all required energy is purchased from the market at projected market prices). The projected operating margin is calculated using the *Prosym*™ simulation model.
- Projected net project benefit—calculated by subtracting fixed and outside variable costs, not included in the *Prosym*™ simulation model, from the projected operating margin.

MARKET PRICE FORECAST

Initially, Avista staff used a market price forecast supplied by Henwood Energy Services, Inc. (HESI) to represent market prices in the *Prosym*™ model. This forecast supplied reasonable monthly on-peak and off-peak market prices for the Pacific Northwest market area. However, the HESI forecast did not provide disaggregated hourly prices and the accompanying report did not provide a detailed description of the assumptions and conditions used in their analysis. As a result, the Avista analysis initially contained 24 market prices per year, an on-peak price and an off-peak price for each month. HESI also provided Avista with a copy of its monthly gas price forecast which it used in developing the market price projections.

After the initial review of Avista's bid analysis, it was determined that the market price forecast needed a higher level of detail in order to improve confidence in the results. The R. W. Beck team suggested several recommendations related to market price projections including, (i) use of an hourly prices and hourly dispatch, (ii) use of monthly gas prices instead of annual average prices, and (iii) forecasting of both energy and capacity prices instead of forecasting all-in prices. R. W. Beck also recommended the use of an additional set of sensitivities in order to create a wider band of market prices to be used in the bid evaluations.

Through discussions with Avista staff, it was decided that a new market price forecast supplied by the R. W. Beck Market Pricing Group would be used in a revised bid analysis. This market price forecast supplied an increased level of detail for the bid review process and also provided Avista staff with an understanding of all the key input assumptions used in the forecast of the long-term prices. Three additional sensitivity price forecasts were created: one using 25 percent higher natural gas prices, one using 25 percent lower natural gas prices, and one with an increase in load by 1.5 percent.

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R. W. BECK'S REVIEW OF THE AVISTA ANALYSIS

R. W. Beck's independent review of Avista's economic analysis of the bids and the self-build option focused on the methodology and key assumptions used in the analysis. The R. W. Beck review team carefully reviewed all of the necessary documents, including the August 2000 RFP, the HESI Market Price Forecast, the model input files, and the initial economic analysis spreadsheets. Numerous conversations between Avista staff and the R. W. Beck review team took place, discussing issues such as model input variables, spreadsheet calculations, the market price forecast, and the meaning of certain terms used in Avista's analysis. The following two subsections summarize our comments on Avista's methodology and the key assumptions used in the analysis.

AVISTA'S ANALYTICAL APPROACH AND METHODOLOGY

Based on our review, R. W. Beck believes the approach taken by Avista in its analysis of the alternative resource proposals provides a fair comparison of the resource options including in the bid proposals or the self-build option. We believe that comparing Avista's total system cost with and without each of the resource options, and the net project benefit of each proposed resource, is a reasonable way to determine which options are most financially and economically viable for Avista.

Avista has used an adequate level of care to include the necessary assumptions and methodology in both the *Prosym*™ modeling of the bids and in the economic analysis spreadsheets. R. W. Beck did not find any material deficiencies (such as miscalculation of formulas or omission of essential data) in either the input files or the electronic spreadsheet analyses.

REVIEW OF KEY ASSUMPTIONS USED IN THE AVISTA ANALYSIS

The following comments focus on a number of the key input assumptions used by Avista in its analysis:

- Market Prices: The annual average market prices used in the initial analysis were within a reasonable range based on recent economic trends and market data. Overall price levels for the Pacific Northwest market were not unreasonable. The use of projected hourly prices in the dispatching analysis allowed for a potentially more fair evaluation of each bid resource and technology type.
- Fuel Prices: We believe the price of gas forecast used was reasonable and based on reputable sources. Monthly price variations follow an expected pattern. Fuel price projections were used appropriately in the model input files.

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- Avista's Resources and Loads: Avista's existing resources and loads were modeled in a reasonable manner based on the data that was provided for review. Operating characteristics of the individual generating units, purchases, and sales were modeled with a reasonable level of accuracy.
- Bids and Self-Build Option: Based on the information contained in each reviewed proposal and information provided on the self-build option, Avista modeled the operational characteristics and costs of each of the resources bid and the self-build option fairly and without bias.
- Inflation, Cost of Capital, and Other Financial Assumptions: Financial and economic parameters used in the evaluation were reasonable and based on recent economic trends.
- Sensitivity Cases: The gas prices used to create the high fuel price and low fuel price sensitivity cases provide for a reasonable range of prices around the base case. Historical market prices for natural gas show a 20 to 25 percent range of volatility. The gas prices used in the sensitivity cases were 25 percent higher and 25 percent lower than the base case scenario, which used market prices.

  The high load sensitivity gives a good indication of how increases in load affect market prices. Although the load sensitivity case, which entails an annual average compounded rate of 1.5 percent increase in loads for all WSCC market areas, does not capture the short-duration load spikes, the sensitivity does provide a reasonable increase in market prices for yearly, weekly, and hourly prices. Short-duration load spikes, such as those occurring during only a few hours each year are captured well in the capacity portion of the market pricing forecast.

CONSIDERATIONS AND ASSUMPTIONS

In the preparation of this letter report and the conclusions that follow, we have made certain assumptions with respect to conditions, which may occur in the future. In addition, we have used and relied upon certain information and assumptions provided to us by sources which we believe to be reliable. We believe the use of such information and assumptions is reasonable for the purposes of this report. However, some assumptions will invariably not materialize as stated herein or may vary significantly due to unanticipated events and circumstances. Therefore, actual results can be expected to vary from those projected to the extent that actual future conditions differ from those assumed by us or provided to us by others.

This independent review included consideration of materials and analyses provided to us by Avista staff. Avista indicated that a representative sample of the various types of bids was provided for our review. Therefore, we did not review all of the bids submitted to

Avista by resource sponsors and we are unaware of those other proposals that Avista may have received, in terms of resource capacity, cost, location, and technology type. R. W. Beck accepted Avista's assumptions, without review, regarding the accessibility of Avista's transmission system for each of the proposed resource options. We did not conduct an independent review of Avista's system import and export capability or Avista's assumptions regarding its ability to purchase from and sell into the regional electricity market.

R. W. Beck was retained to conduct an independent review of the economic analysis of the bids and the self-build option. According to Avista staff, in addition to the economic analysis, other non-economic and non-financial factors will also be used to determine the merit of the submitted bids (including items such as credit-worthiness of resource sponsors, environmental factors, etc.). Avista's economic analysis will comprise only a portion of the evaluation process used to judge each of the bids and the self-build option. R. W. Beck did not review any of these non-economic factors nor the final process for determining the winning resource option.

CONCLUSIONS

Based on the review summarized in this letter report and the considerations and assumptions set forth above, R. W. Beck concludes that:

- Avista's bid evaluation methodology and assumptions were sound. Avista staff included all the necessary input variables into the *Prosym*™ model and the economic analysis spreadsheets.
- R. W. Beck's recommended modifications to forecasted market prices were addressed in order to improve the bid review analysis. Avista was committed to creating a fair and accurate bid-review process and invested the required time and resources to do so.
- Avista's approach provided a fair and reasonable methodology to determine which bid option is most viable for Avista. The bid review process was based on sound financial and economic assumptions and the analysis used appropriate information to make decisions regarding future markets and Avista's system needs.
- The approach taken by Avista provided for a fair comparison of the resource options bid as well as the self-build option. The market prices used in the analysis provide a reasonable level of detail and a wide enough range of prices so that bids may be assessed fairly under a variety of market circumstances. All bids reviewed were represented fairly in the *Prosym*™ model and the financial analysis spreadsheets.

R·W·BECK

We appreciate the opportunity to be of service to Avista Corporation in its evaluation of its future resource options, and we hope to have the opportunity to work with you again in the near future.

Sincerely,

R. W. BECK, INC.

Richard Cuthbert

Richard W. Cuthbert
Project Manager

Angelo Muzzin

Angelo Muzzin
Client Services Director
Pacific Northwest

RWC:bb

File: 011129 / 11-00669-10101-0101

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-11)

One-Year Forward Implied Heat Rate

Mid-C Electric Contract to NYMEX Henry Hub Natural Gas: 1-25-00 through 11-12-01

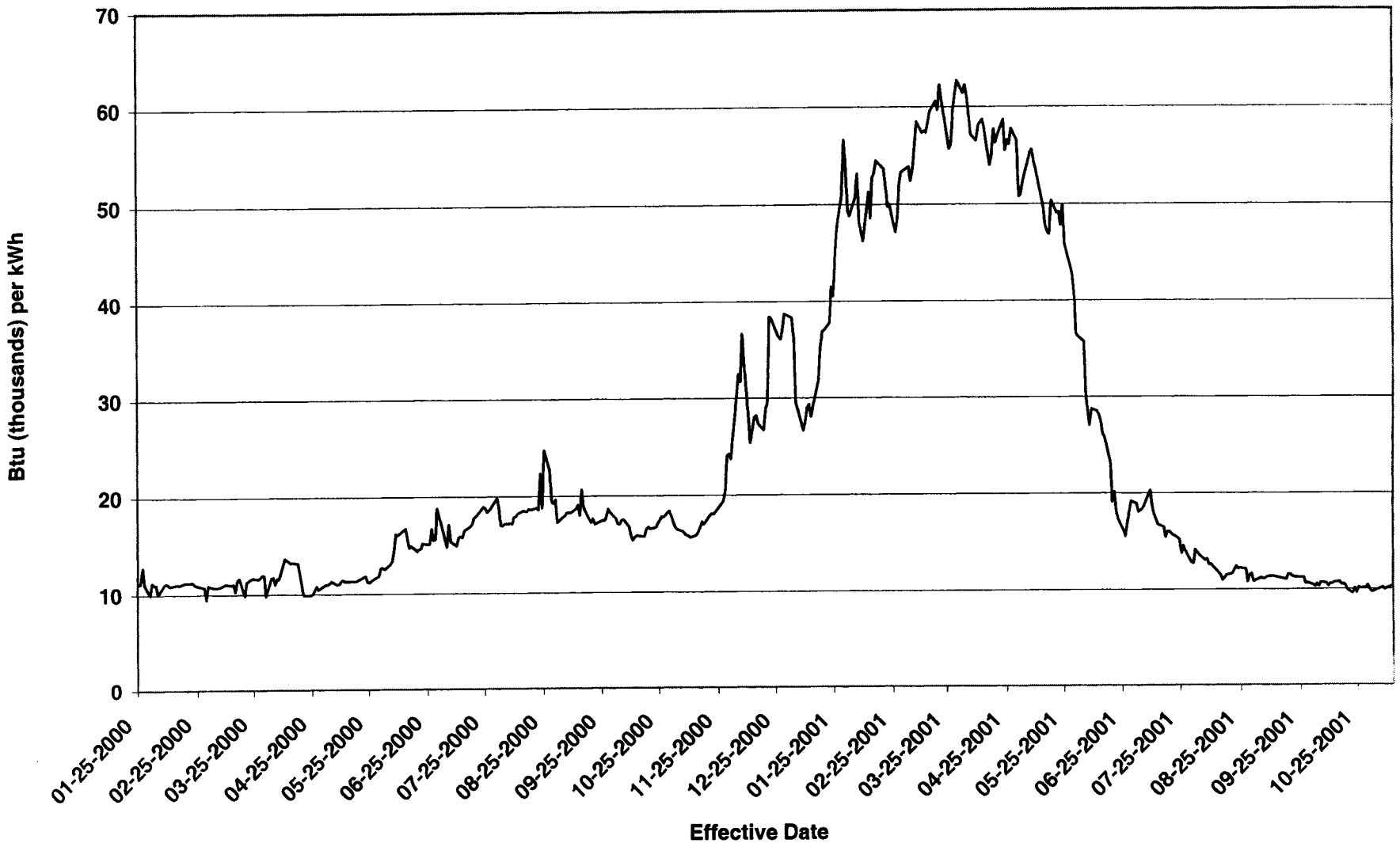


Exhibit No.____(RJL-11)
Docket No. UE-01____
Page 1 of 1

Spark Spread_1Yr Forward Strips.xls, 11-27-2001, bjs

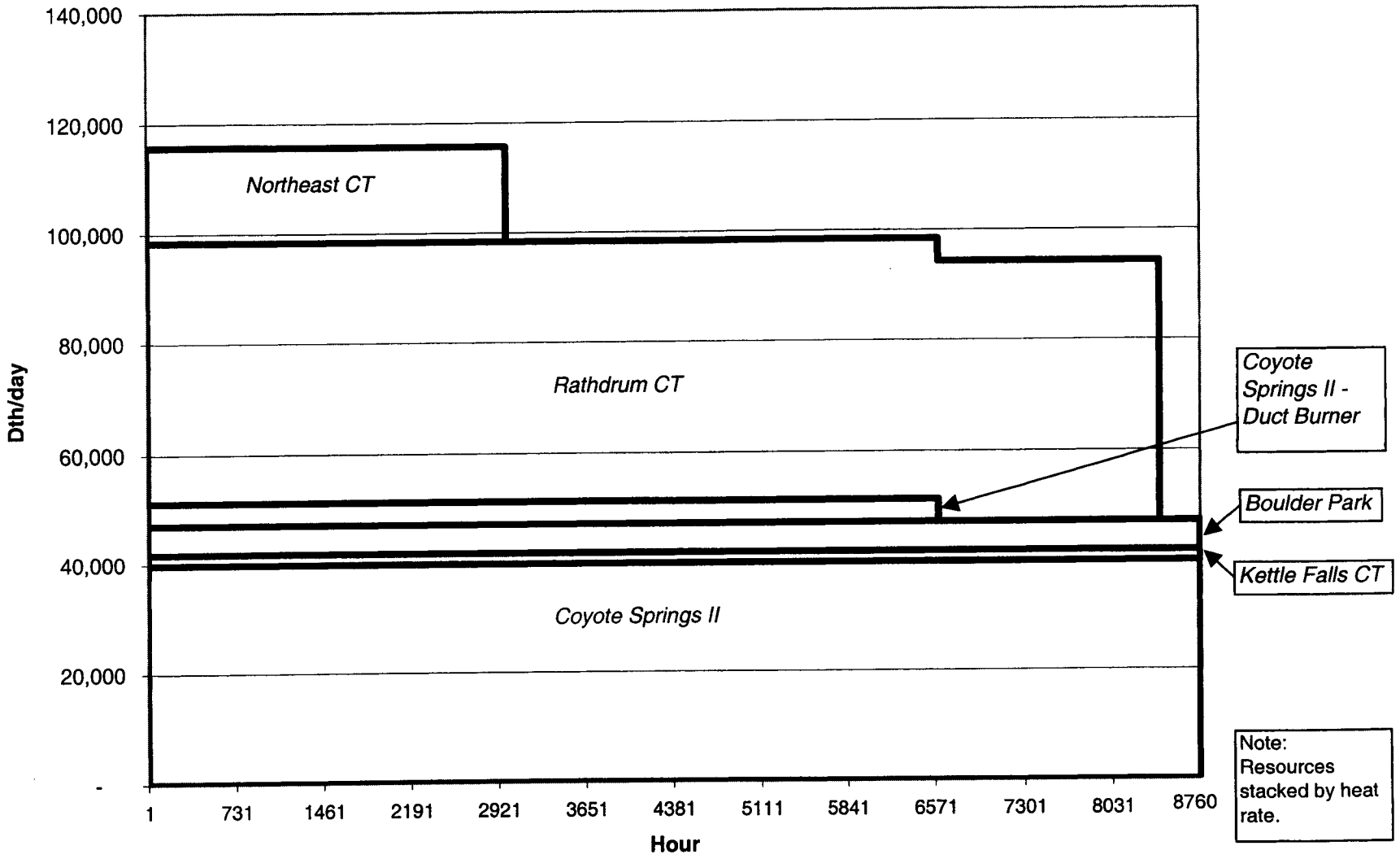
BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-13)

Average Maximum Daily Natural Gas Consumption By Generation Project For A One Year Period



11-26-2001

Avista Corporation
Natural Gas for Thermal Generation

Maximum Daily Natural Gas Consumption

	NECT (dth/day)	Rathdrum (dth/day)	Boulder Park (dth/day)	KFCT (dth/day)	CSII (dth/day)	CSII Duct (dth/day)	Total (dth/day)
Jan	18,720	49,630	5,358	1,995	41,844	4,357	121,904
Feb	18,408	49,050	5,358	1,995	41,194	4,290	120,295
Mar	17,784	48,123	5,358	1,995	40,410	4,200	117,869
April	17,472	47,137	5,358	1,995	39,675	4,133	115,771
May	17,160	46,209	5,358	1,995	38,958	4,044	113,724
June	17,160	45,514	5,358	1,995	38,341	3,999	112,366
July	15,600	44,586	5,358	1,995	37,707	3,932	109,178
Aug	15,600	44,702	5,358	1,995	37,807	3,932	109,394
Sept	17,160	45,688	5,358	1,995	38,508	3,999	112,707
Oct	17,472	47,021	5,358	1,995	39,642	4,133	115,621
Nov	17,784	48,645	5,358	1,995	40,960	4,267	119,009
Dec	18,720	49,456	5,358	1,995	41,728	4,334	121,591

Annual Ave. Max. Daily Nat. Gas Consumption	17,420	47,147	5,358	1,995	39,731	4,135	115,786

Annual Ave. Max. Daily Nat. Gas Consumption based on Air Permit Operating Hours	5,966	45,338	5,358	1,995	39,731	3,115	101,504

	Annual Ave. Daily Natural Gas Requirement (dth/day)	% Of Nat. Gas Hedged for Period 11-1-01 through 12-31-01	% Of Nat. Gas Hedged for Period 1-1-01 through 5-31-02	% Of Nat. Gas Hedged for Period 6-1-02 through 10-31-03	% Of Nat. Gas Hedged for Period 11-1-03 through 10-31-04
Coyote Springs II	42,847	N.A.	N.A.	93%	47%
Rathdrum	45,338	44%	32%	N.A.	N.A.
Boulder Park	5,358	N.A.	100%	N.A.	N.A.

Notes:
1) Period 11-1-01 through 12-31-01; 20,000 Dth/day hedged
2) Period 1-1-02 through 5-31-02; 20,000 Dth/day hedged
3) Period 6-1-02 through 10-31-03; 40,000 Dth/day hedged
4) Period 11-1-03 through 10-31-04; 20,000 Dth/day hedged
5) N.A. means that the plant either is not available or it is not the most economic plant available to use the nat. gas

Exhibit No.____(RJL-13)
Docket No. UE-01____
Page 2 of 2

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-15)

...oliday reminder

Gas Daily will not publish April 13 in observance of Good Friday. The next issue will appear April 16. The Daily Price Survey published in the April 16 issue will cover transactions conducted April 12 for gas flow April 13-16.

NYMEX will be closed April 13. NYMEX Access will be closed April 12 and is scheduled to reopen the evening of April 15.

Gas Daily reader survey

Gas Daily's new 2001 subscriber survey — your chance to win a $200 Golfdiscount.com gift certificate. Visit www.ftenergyusa.com/gasdaily/gdsurvey.asp.

FUTURES
NYMEX @ Henry Hub

Results from Tuesday

	Settlement	High	Low	Change	Volume
May., 2001	5.559	5.620	5.520	8.2	22,204
June	5.611	5.660	5.540	7.5	7,965
July	5.657	5.700	5.630	7.2	1,311
August	5.692	5.740	5.675	7.2	2,473
September	5.672	5.710	5.660	7.2	873
October	5.682	5.720	5.675	7.2	2,029
November	5.807	5.850	5.780	7.2	517
December	5.920	5.970	5.890	7.2	1,358
Jan., 2002	5.957	6.005	5.945	7.2	938
February	5.767	5.820	5.760	6.7	1,272
March	5.422	5.480	5.410	6.7	667
April	4.832	4.860	4.830	4.2	770
May	4.687	4.750	4.680	3.2	309
June	4.698	4.750	4.660	3.8	335
...ly	4.728	—	—	3.8	40
...gust	4.735	4.750	4.720	3.8	479
...ptember	4.712	4.750	4.720	3.5	622
October	4.712	4.700	4.670	3.5	96
November	4.827	4.890	4.810	3.5	24
December	4.932	4.950	4.935	3.5	24
Jan., 2003	4.962	5.030	4.980	3.5	298
February	4.789	4.810	4.810	3.5	37
March	4.549	4.610	4.560	3.5	72
April	4.254	4.270	4.250	1.0	231
May	4.192	—	—	0.3	280
June	4.205	—	—	0.3	130
July	4.230	—	—	0.3	30
August	4.255	4.280	4.280	0.3	31
September	4.245	—	—	0.3	30
October	4.245	—	—	0.3	30
November	4.355	—	—	0.3	30
December	4.475	4.472	4.472	0.3	35
Jan., 2004	4.515	4.550	4.512	0.3	106
February	4.395	4.380	4.380	0.3	1
March	4.255	4.250	4.240	0.3	22
April	4.113	—	—	0.3	0

Volume of contracts (unofficial) 45,669
Front-months open interest Monday:
May, 41,900; June, 21,783; July, 17,326
Total open interest Monday: 372,720
Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

OPTIONS
NYMEX@Henry Hub

Results from Tuesday

Strike Price	Calls-Settle May.	Jun.	Jul.	Puts-Settle May.	Jun.	Jul.
5.40	—	—	—	14.2¢	28.9¢	40.0¢
5.45	—	—	—	16.2¢	31.1¢	42.3¢
5.50	—	—	—	18.4¢	33.4¢	44.7¢
5.55	—	—	—	20.8¢	35.8¢	47.2¢
5.60	19.2¢	39.4¢	57.0¢	—	38.3¢	49.7¢
5.65	17.2¢	37.2¢	53.4¢	—	—	52.4¢
5.70	15.4¢	35.1¢	51.2¢	—	—	—
...	13.7¢	33.1¢	49.1¢	—	—	—
...	—	—	—	—	—	—

Estimated Volume: Calls: n/a Puts: n/a
Total open interest Monday Calls: 149,832 Puts: 206,259
Not all strike and settlement prices listed.
Implied Volatility for at-the-money strike price
Calls: n/a Puts: n/a Source: Bloomberg

Talisman spins plan to acquire Petromet

Talisman Energy will acquire Calgary-based Petromet Resources in a cash offer at a price of C$13.20/share, representing a 26% premium over the closing price of the Petromet shares on April 9.

"This is a good marriage of assets, infrastructure and upside poten... ...a," said Talisman President and CEO Jim Buckee. "We intend to consolidate ... omet's Canadian assets into a partnership following completion of ...

"Petromet's assets tie nicely into our rapidly gr... ...een building on our existing land base near the Ta... ...st year with the acquisition of midstream as... ... tion of properties acquired from R...

A Talisman spokesman ... June 1, is expected to ...

With this a... than 850 m... 2002. P... ...said it ex...

...il and liquids w... ...ights to more than ... drilling locations. ...x pools is approximately C$638 ... and C$1.12/mcfe (C$6.72/boe) proved ...crate more than C$250 million of cash flow in ... production for the remainder of 2001 at approximately 110 m... ... obl/d of liquids. More than 90% of the asset value is concentrated in two properties — Bigstone and Wild River. Petromet's average working interest in its production is 85%.

The company said it expects to mail its offer to Petromet shareholders and debenture holders on or about April 20. The offer will be conditional upon not less than two-thirds of the Petromet shares and 90% of the Petromet debentures being tendered.

Petromet's board of directors has unanimously voted to recommend acceptance of the offer by the Petromet shareholders and debenture holders. JM

Questar signs deal for portion of Southern Trails

Questar Pipeline said it has concluded a contract with Duke Energy covering all of the capacity for the 80,000 dth/d east zone of its $155 million Southern Trails Pipeline project, a project that involves converting a crude oil pipeline to natural gas. The 705-mile pipeline runs from the Four Corners areas near Blanco, N.M., to Long Beach, Calif., and is divided into east and west zones.

The east zone can transport gas from multiple receipt points in the San Juan Basin to multiple delivery points near the California border. "This contract moves us one very large step closer to making the Southern Trails Pipeline a reality," Questar Pipeline President and CEO D.N. Rose said.

The company also is soliciting interest from customers for Southern Trails' west zone, which runs from the California state line to Long Beach. The west zone will have a capacity of 120,000 dth/d. Questar began work on the east zone last year after receiving FERC approval for the entire project last July.

The west zone is encountering regulatory and utility tariff barriers in California, similar to resistance confronted by other interstate pipelines that have tried to supply gas service into the state's market areas. Questar is proceeding with the east portion as if it were a separate project, Questar spokesman Chad Jones said. The project has received interest in the west zone from potential shippers, contingent on SoCal Gas changing its tariff to make it economically feasible to take gas from a competitive pipeline.

Questar pointed to a Residual Load Service fee imposed by SoCal Gas that "deters existing customers from using alternate natural gas suppliers if they elect to switch part of their transportation to a competing pipeline in Southern California Gas' service area."

Options that SoCal Gas has proposed in response to California Public Utilities Com-

Michigan clicks on choice

According to the Michigan Public Service Commission, gas customers in the state are showing more interest in the state's customer choice program. As evidence, the PSC pointed to the number of times that the program information Web page has been accessed in recent months.

During March, the PSC's choice comparison of suppliers and prices page received nearly 12,000 hits. Moreover, seven other choice program-related pages were viewed an additional 16,000 times.

The increased consumer interest "will encourage expanded participation by natural gas marketers in Michigan's customer choice programs," said PSC Chairwoman Laura Chappelle. VK

FUTURES
NYMEX @ Henry Hub

Results from Wednesday

	Settlement	High	Low	Change	Volume
Jun., 2001	4.202	4.315	4.145	-7.7	0
July	4.273	4.385	4.220	-8.0	0
August	4.343	4.450	4.290	-8.2	0
September	4.369	4.465	4.330	-8.6	0
October	4.400	4.500	4.360	-9.3	0
November	4.574	4.674	4.550	-9.9	0
December	4.748	4.855	4.710	-10.5	0
Jan., 2002	4.813	4.925	4.775	-11.0	0
February	4.693	4.820	4.650	-11.0	0
March	4.510	4.679	4.490	-10.3	0
April	4.200	4.300	4.190	-9.3	0
May	4.131	4.230	4.130	-9.2	0
June	4.173	4.265	4.170	-9.2	0
July	4.223	4.315	4.200	-9.2	0
August	4.242	4.340	4.230	-9.8	0
September	4.247	4.345	4.270	-9.8	0
October	4.267	4.305	4.285	-9.8	0
November	4.407	4.505	4.420	-9.8	0
December	4.537	4.635	4.550	-9.8	0
Jan., 2003	4.587	4.685	4.600	-9.8	0
February	4.442	4.535	4.475	-9.3	0
March	4.255	4.295	4.287	-9.2	0
April	3.970	4.055	3.995	-8.5	0
May	3.935	3.960	3.930	-8.5	0
June	3.975	3.975	3.975	-8.5	0
July	4.025	4.160	4.160	-8.5	0
August	4.070	4.070	4.070	-7.8	0
September	4.087	4.087	4.087	-7.3	0
October	4.102	4.102	4.102	-6.8	0
November	4.214	4.240	4.230	-6.6	0
December	4.349	4.349	4.349	-6.6	0
Jan., 2004	4.407	4.407	4.407	-6.6	0
February	4.287	4.287	4.287	-6.6	0
March	4.148	4.148	4.148	-6.6	0
April	3.978	3.978	3.978	-6.6	0
May	3.948	3.948	3.948	-6.6	0

Volume of contracts (unofficial) 0
Front-months open interest Tuesday:
June, 44,175; July, 24,183; August, 28,813
Total open interest Tuesday: 409,385
Weighted average of x number of trades in the last two minutes of trading. Change is from previous settlement price.

OPTIONS
NYMEX@Henry Hub

Results from Wednesday

Strike Price	Calls-Settle Jun.	Jul.	Aug.	Puts-Settle Jun.	Jul.	Aug.
4.05	—	—	—	11.5¢	22.4¢	—
4.10	—	41.5¢	—	13.6¢	—	30.6¢
4.15	—	—	—	15.8¢	26.7¢	—
4.20	17.5¢	—	—	18.2¢	29.0¢	35.2¢
4.25	16.3¢	33.5¢	—	18.5¢	31.5¢	37.5¢
4.30	14.2¢	31.1¢	47.5¢	—	—	40.0¢
4.35	12.4¢	28.9¢	41.5¢	—	—	42.5¢
4.40	10.7¢	—	39.2¢	27.0¢	—	—
4.45	—	—	—	—	—	—

Estimated Volume: Calls: n/a Puts: n/a
Total open interest Tuesday Calls: n/a Puts: n/a
Not all strike and settlement prices listed.
Implied Volatility for at-the-money strike price
Calls: 55.39% Puts: 51.32% Source: Bloomberg

SoCal Ed presses FERC to ma' ...ly public

Firing off another round in the paper war over Califor... ...uthern Califor-nia Edison on Tuesday asked FERC for permis... ...power study that it says proves that El Paso and its affili... ...o drive up prices in the state. And the *New York Time*... ...ry, pub-lishing an article that focused on the uti... ...ies.

As reported in *Gas Daily*, SoC... ...are blaming El Paso for alleged mar... ...and capacity manipulation. F... ...dismissed the CPUC's c... ...of pipeline capacity in ...

Now SoCal ... ...sachusetts-based consul... ...oned the study, the repo... ...withholding capac-ity ... ...ed to the lack of suffi-ci... ...fect of raising both natural ... said SoCal Ed.

...ate market manipulation by El Paso ...t. SoCal Ed reckoned that its electricity ...esult of El Paso's anticompetitive practices. ...ase are concerned about the protection of sensi-... contained in case proceedings as well as in The ..., FERC Chief Administrative Law Judge Curtis Wagner ...ge of materials in the case.

...g FERC to reconsider the protected status of study. According to the ... ...s right to know outweighs any possible confidentiality concern over material which is mere historical data, which is not contract or customer specific and which is the product of a study performed on behalf of [SoCal Ed]."

The conclusions of The Brattle Group study, however, are already circulating in public. Most recently, the *Times* ran an article that gave considerable play to The Brattle Group's findings.

El Paso has forwarded its own version of the California gas price controversy. According to a study conducted by Lukens Consulting Group and commissioned by El Paso, broader market forces were at work in driving up the price of gas in the Golden State (*GD 4/25*).

Joan Dreskin of the Interstate Natural Gas Association of America, which represents the pipeline industry, said that there should be no rush to judgement in the capacity case. "Neither the press nor the public should jump to conclusions that there was any wrongdoing by either El Paso or its marketing affiliates," she said. "There's a hearing at FERC that will review their conduct ... without having all the facts, the allegations should not be decided by the press," she said. NH

GAO prepares to investigate high gas prices

Even as gas prices fall toward the $4 mark, the investigations continue. The U.S. Congress got in on the act this week, launching a probe into the cause of high natural gas prices.

In response to several requests by members of Congress, the General Accounting Office — the investigative arm of Congress — said it would begin a search into why gas prices have risen over the past couple of years and what caused the record-high costs this past winter.

In a March 30 letter, six House representatives sent a letter to GAO Comptroller General David Walker, questioning why gas prices have risen so dramatically. The letter was signed by Reps. John Spratt, D-S.C., Jan Schakowsky, D-Ill., Bud Cramer, D-Ala., Bob Etheridge, D-N.C., Ed Markey, D-Mass., and Mike Thompson, D-Calif.

"We are alarmed at this spike in the cost of natural gas and the impact on our constituents," the letter stated.

The letter requests that the GAO investigate gas supply availability from domestic and imported production during the recent period of high prices; changes in gas demand by customer class; and the impact of increased demand for electric generation on gas prices.

In addition, the legislators asked that the GAO look into the role of trading futures on the NYMEX, gas forward contracts, and any over-the-counter derivative contracts involving gas

Table 4. U. S. Energy Prices

(Nominal Dollars)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Crude Oil Prices															
Imported Average[a]	**26.84**	**26.55**	**29.11**	*28.27*	*24.57*	*24.50*	*26.00*	*27.00*	*26.33*	*26.00*	*26.50*	*26.83*	*27.72*	*25.52*	*26.41*
WTI[b] Spot Average	**28.82**	**28.78**	**31.61**	*31.96*	*28.82*	*27.67*	*29.04*	*30.01*	*29.34*	*29.00*	*29.50*	*29.83*	*30.29*	*28.88*	*29.42*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**2.26**	**3.06**	**3.87**	*5.22*	*6.27*	*4.50*	*4.55*	*5.40*	*5.32*	*4.42*	*4.32*	*5.18*	*3.62*	*5.18*	*4.82*
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	**1.44**	**1.57**	**1.56**	*1.54*	*1.47*	*1.52*	*1.53*	*1.47*	*1.46*	*1.49*	*1.49*	*1.46*	*1.53*	*1.50*	*1.47*
Regular Unleaded	**1.40**	**1.53**	**1.52**	*1.50*	*1.43*	*1.49*	*1.50*	*1.43*	*1.42*	*1.46*	*1.45*	*1.42*	*1.49*	*1.46*	*1.44*
No. 2 Diesel Oil, Retail															
(dollars per gallon)	**1.42**	**1.41**	**1.50**	*1.58*	*1.47*	*1.41*	*1.42*	*1.46*	*1.43*	*1.42*	*1.42*	*1.45*	*1.48*	*1.44*	*1.43*
No. 2 Heating Oil, Wholesale															
(dollars per gallon)	**0.85**	**0.78**	**0.91**	*0.97*	*0.84*	*0.74*	*0.77*	*0.86*	*0.83*	*0.76*	*0.77*	*0.85*	*0.88*	*0.81*	*0.81*
No. 2 Heating Oil, Retail															
(dollars per gallon)	**1.31**	**1.17**	**1.23**	*1.40*	*1.34*	*1.18*	*1.12*	*1.27*	*1.28*	*1.17*	*1.12*	*1.26*	*1.31*	*1.28*	*1.24*
No. 6 Residual Fuel Oil, Retail[d]															
(dollars per barrel)	**23.64**	**24.55**	**25.10**	*27.40*	*24.52*	*23.35*	*23.79*	*25.53*	*25.02*	*23.38*	*23.61*	*24.62*	*25.34*	*24.30*	*24.14*
Electric Utility Fuels															
Coal															
(dollars per million Btu)	**1.21**	**1.21**	**1.18**	*1.20*	*1.21*	*1.22*	*1.20*	*1.20*	*1.20*	*1.21*	*1.19*	*1.18*	*1.20*	*1.21*	*1.20*
Heavy Fuel Oil[e]															
(dollars per million Btu)	**3.74**	**4.18**	**4.34**	*4.46*	*3.82*	*3.83*	*3.97*	*4.07*	*3.88*	*3.84*	*3.94*	*3.95*	*4.25*	*3.90*	*3.90*
Natural Gas															
(dollars per million Btu)	**2.85**	**3.78**	**4.46**	*5.91*	*6.91*	*5.15*	*5.16*	*6.02*	*6.02*	*5.03*	*4.92*	*5.79*	*4.25*	*5.61*	*5.27*
Other Residential															
Natural Gas															
(dollars per thousand cubic feet)	**6.53**	**7.77**	**10.09**	*8.68*	*9.91*	*10.58*	*11.04*	*9.12*	*9.47*	*10.12*	*11.02*	*9.35*	*7.69*	*9.88*	*9.65*
Electricity															
(cents per kilowatthour)	**7.78**	**8.37**	**8.59**	*8.21*	*7.97*	*8.56*	*8.81*	*8.35*	*7.98*	*8.54*	*8.81*	*8.33*	*8.25*	*8.44*	*8.43*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] West Texas Intermediate.

[c] Average self-service cash prices.

[d] Average for all sulfur contents.

[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Table 4. U. S. Energy Prices

(Nominal Dollars)

	2000				2001				2002				Year		
	1st	2nd	3rd	4th	1st	2nd	3rd	4th	1st	2nd	3rd	4th	2000	2001	2002
Crude Oil Prices															
Imported Average[a]	**26.84**	**26.55**	**29.12**	*28.25*	*24.57*	*25.00*	*27.00*	*27.00*	*26.33*	*26.00*	*26.50*	*26.83*	*27.72*	*25.91*	*26.41*
WTI[b] Spot Average	**28.82**	**28.78**	**31.61**	*31.96*	*28.82*	*28.44*	*30.14*	*30.04*	*29.34*	*29.00*	*29.50*	*29.83*	*30.29*	*29.36*	*29.42*
Natural Gas Wellhead															
(dollars per thousand cubic feet)	**2.26**	**3.06**	**3.87**	*5.22*	*6.27*	*4.57*	*4.73*	*5.52*	*5.38*	*4.48*	*4.36*	*5.19*	*3.62*	*5.27*	*4.86*
Petroleum Products															
Gasoline Retail[c] (dollars per gallon)															
All Grades	**1.44**	**1.57**	**1.56**	*1.54*	*1.47*	*1.66*	*1.61*	*1.53*	*1.48*	*1.51*	*1.50*	*1.47*	*1.53*	*1.57*	*1.49*
Regular Unleaded	**1.40**	**1.53**	**1.52**	*1.50*	*1.43*	*1.62*	*1.58*	*1.50*	*1.44*	*1.48*	*1.47*	*1.44*	*1.49*	*1.53*	*1.46*
No. 2 Diesel Oil, Retail (dollars per gallon)	**1.42**	**1.41**	**1.50**	*1.58*	*1.47*	*1.47*	*1.48*	*1.49*	*1.45*	*1.43*	*1.43*	*1.46*	*1.48*	*1.48*	*1.44*
No. 2 Heating Oil, Wholesale (dollars per gallon)	**0.85**	**0.78**	**0.91**	*0.97*	*0.83*	*0.75*	*0.80*	*0.86*	*0.84*	*0.76*	*0.77*	*0.85*	*0.88*	*0.82*	*0.81*
No. 2 Heating Oil, Retail (dollars per gallon)	**1.31**	**1.17**	**1.23**	*1.40*	*1.35*	*1.19*	*1.15*	*1.28*	*1.29*	*1.18*	*1.12*	*1.26*	*1.31*	*1.28*	*1.25*
No. 6 Residual Fuel Oil, Retail[d] (dollars per barrel)	**23.62**	**24.57**	**25.10**	*27.41*	*24.99*	*24.52*	*25.22*	*26.27*	*25.57*	*23.83*	*23.90*	*25.24*	*25.34*	*25.26*	*24.64*
Electric Utility Fuels															
Coal (dollars per million Btu)	**1.21**	**1.21**	**1.18**	*1.20*	*1.21*	*1.23*	*1.21*	*1.20*	*1.21*	*1.22*	*1.19*	*1.18*	*1.20*	*1.21*	*1.20*
Heavy Fuel Oil[e] (dollars per million Btu)	**3.74**	**4.18**	**4.34**	*4.52*	*3.90*	*4.02*	*4.20*	*4.18*	*3.97*	*3.91*	*3.98*	*4.03*	*4.27*	*4.05*	*3.97*
Natural Gas (dollars per million Btu)	**2.85**	**3.78**	**4.46**	*6.33*	*7.61*	*5.62*	*5.56*	*6.24*	*6.14*	*5.11*	*4.97*	*5.81*	*4.33*	*6.03*	*5.33*
Other Residential															
Natural Gas (dollars per thousand cubic feet)	**6.53**	**7.77**	**10.09**	*8.68*	*9.91*	*10.59*	*11.12*	*9.26*	*9.58*	*10.20*	*11.08*	*9.39*	*7.69*	*9.93*	*9.73*
Electricity (cents per kilowatthour)	**7.76**	**8.35**	**8.57**	*8.26*	*8.10*	*8.79*	*9.00*	*8.50*	*8.11*	*8.63*	*8.87*	*8.38*	*8.25*	*8.61*	*8.51*

[a] Refiner acquisition cost (RAC) of imported crude oil.

[b] West Texas Intermediate.

[c] Average self-service cash prices.

[d] Average for all sulfur contents.

[e] Includes fuel oils No. 4, No. 5, and No. 6 and topped crude fuel oil prices.

Notes: Data are estimated for the fourth quarter of 2000. Prices exclude taxes, except prices for gasoline, residential natural gas, and diesel. The forecasts were generated by simulation of the Short-Term Integrated Forecasting System.

Sources: Historical data: Energy Information Administration: latest data available from EIA databases supporting the following reports: *Petroleum Marketing Monthly*, DOE/EIA-0380; *Natural Gas Monthly*, DOE/EIA-0130; *Monthly Energy Review*, DOE/EIA-0035; *Electric Power Monthly*, DOE/EIA-0226.

Non-OPEC production is expected to increase by another 0.6 million barrels per day in 2001, with much of this increase coming from Russia. Although the Caspian Pipeline Consortium has begun filling its new pipeline to transport oil from Kazakhstan to world markets, this is not expected to support greater Caspian production levels until end-2001.

International Oil Demand. World oil demand remains expected to grow, despite concerns over a gradual economic slowdown in the industrialized countries. EIA projects world oil demand growth of 1.4 million barrels per day in 2001 (higher than the IEA's 1.3 million barrels per day prediction), with slightly higher demand growth expected for 2002. Besides the OECD, non-OECD Asia is still expected to be the leading region for oil demand growth over the next two years, although this growth now appears to be weaker than previously assumed.

World Oil Inventories. EIA does not attempt to estimate oil inventory levels on a global basis. However, the direction in which global oil inventories are headed is discerned from EIA's world oil supply and demand estimates. Stocks are currently below "normal" levels, although not by so wide a margin as EIA previously believed, and these low inventory levels are expected to put upward pressure on prices. U.S. crude oil stocks, for example, are expected to remain below normal levels for most of 2001 and to improve in 2002 but only into the lower end of the normal range (Figure 9).

U. S. Energy Prices

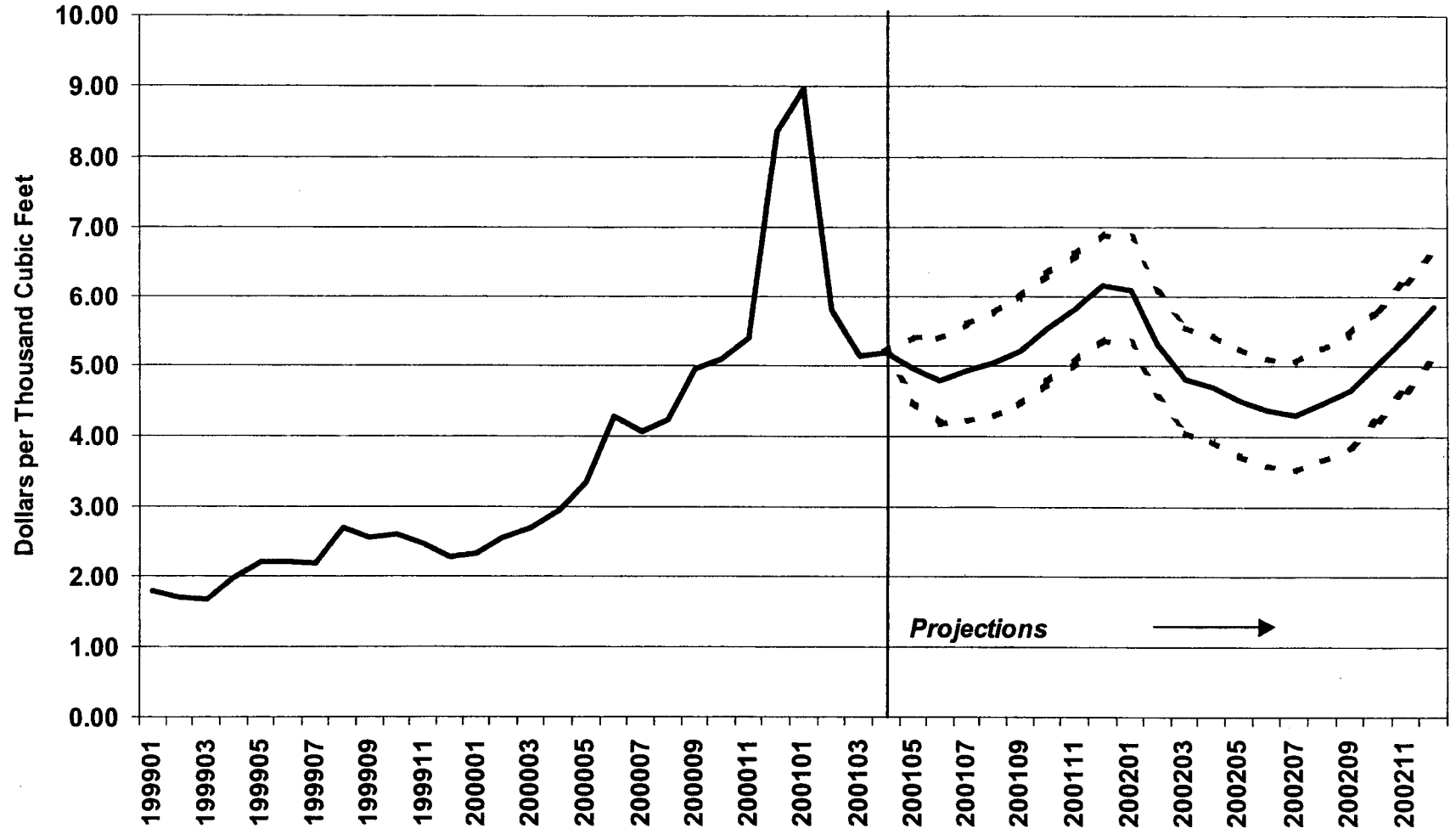
Motor Gasoline. As noted above, pump prices have been soaring due to high demand and low inventories. The tightening of motor gasoline stocks, which are less plentiful now than they were this time last year and have helped push prices into new territories.

As a result, we project that the average monthly pump price for regular gasoline will range between $1.50 and $1.75 per gallon, perhaps more, during the peak months of the driving season. Last year, the high national average prices were skewed by exceedingly high pump prices in the Midwest (over $2.00 per gallon at times), which, in turn, were the result of critical regional supply problems. Although in our base case we do not necessarily project a repeat of last year, the current situation of relatively low inventories for gasoline sets the stage for potential regional imbalances in supply that could bring about significant price volatility in the U.S. gasoline market.

Distillate Fuel Oil (Diesel and Heating Oil). The recent surge in motor gasoline prices may impact the retail price of diesel fuel oil. Since there is currently a supply deficit for motor gasoline, refiners will need to emphasize gasoline production at the expense of distillate. Even though inventories of distillate fuel are adequate, supplies of this fuel may become tighter during the summer as distillate production lags, resulting in a premium for its price. As a result, retail diesel prices are expected to remain fairly high in historical terms, averaging close to $1.50 per gallon during the driving season. Moreover, consumption of distillate fuel in place of natural gas for power generation could put additional pressure on the diesel fuel market, although such a development is rather unlikely unless electricity demand surges sharply in key gas-consuming regions.

Natural Gas. Last winter (October 2000-March 2001) natural gas prices at the wellhead averaged $5.74 per thousand cubic feet, more than double the previous winter's price. Natural gas prices (Figure 10) began climbing last summer primarily in response to low levels of underground gas storage. Compared to this time last year, storage levels are still low. As a result, spot prices are currently averaging about $5.00 per thousand cubic feet. We continue to believe that, given the current state of the natural gas market, it will be a while before prices at the wellhead return to the low level of $2.00 per thousand cubic feet experienced just one year ago. About 90 percent of the planned additions to electric generating capacity over the next few years are designed to primarily use natural gas as a fuel source. For the spring and summer, average

Figure 10. Natural Gas Spot Prices
(Base Case and 95% Confidence Interval)



Sources: History: Natural Gas Week; Projections: Short-Term Energy Outlook, May 2001.

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wellhead prices are projected to decline only modestly, averaging an unseasonably strong $4.65 per thousand cubic feet. One factor that should keep prices relatively high is the need for unusually large refill volumes for underground storage. The gas supply situation this injection season bears close monitoring. If the spring and summer weather is particularly hot in regions that consume large quantities of gas-fired electricity, (California and Texas for example), then injections into underground storage for the next winter would again be strained, resulting once more in sharply rising prices from already robust current levels. In 2001, the annual average wellhead price is projected to average over $5.00 per thousand cubic feet. Next year, we expect the storage situation to improve somewhat and with that, we expect a dip in the average annual wellhead price. Increases in production and imports of natural gas needed to keep pace with the rapidly growing demand for natural gas will be accompanied, for the time being, by relatively expensive supplies for gas due to rising production costs and capacity constraints on the pipelines.

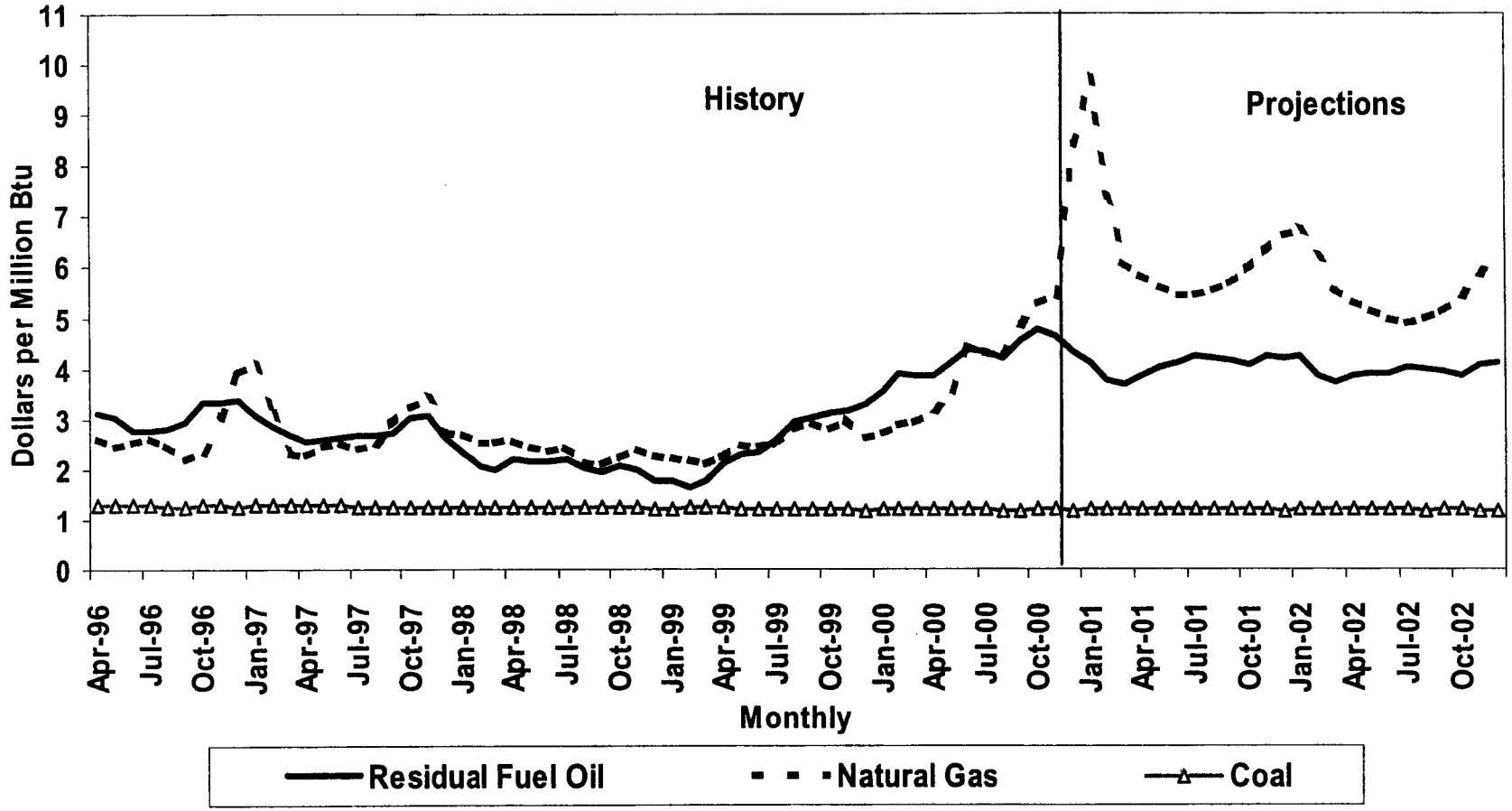
Electric Utility Fuels. The rapid rise in gas prices last summer and fall has pulled delivered gas prices above heavy fuel oil prices on a cost per Btu basis (Figure 11). As this situation is likely to persist, we anticipate some recovery in the amount of heavy fuel oil used for power generation over the very low levels seen since late 1999. In 2001, the cost of coal to electric utilities is projected to increase slightly, after years of slow but continual decline, as coal, like oil, is being used more intensively for electricity generation in lieu of expensive or unavailable natural gas. On an inflation-adjusted basis, however, coal prices should still show a decline this year.

U.S. Oil Demand

Petroleum demand data for 2000 have been revised. (The more detailed view of the revisions is provided in EIA's latest *Petroleum Supply Monthly*). Compared to previous Short-Term Energy Outlook, these revisions, brought about primarily by revisions to imports data, result in an overall 0.9-percent increase in total estimated demand in 2000 compared to the preliminary figures. As a result, total demand increased from 19.52 million barrels per day in 1999 to 19.68 million barrels per day in 2000, an increase of 0.8 percent. This contrasts with a 0.1-percent decline based on the original data. The demand revisions involved upward adjustments in most major product categories. In contrast to the 0.6-percent decline based on the original data, motor gasoline demand now exhibits a 0.5-percent growth rate from the 1999 level, a revision of 1.1 percent. The year-to-year increase in jet-fuel demand has been revised from 2.0 percent to 3.2 percent. In addition, distillate fuel and residual fuel oil demands registered increases of 3.4 and 9.4 percent, up from 3.2 and 1.8 percent based on the preliminary data. The liquefied petroleum products group also underwent an increase but the year-to-year change was still slightly negative. Other minor petroleum products generally registered downward revisions. In general, these revisions reduce the responsiveness to price change that one may reasonably attribute to the petroleum demand weakness witnessed in 2000. As it turns out, the numbers now line up somewhat better, on balance, with the sorts of results one would expect using the short-run price elasticities embedded in the model used for the Short-Term Energy Outlook. However, these elasticities have always been small in absolute value, so the change is not one that is particularly worrisome from the standpoint of consistency with accumulated experience.

Total petroleum products demand is projected to climb an average 250,000 barrels per day, or 1.3 percent, in 2001. Data for the first quarter of this year indicate a sizable year-to-year 510,000 barrels-per day, or 2.6-percent, increase in total petroleum demand. But much of that increase stems from special factors. The most important is the weather, which, although only moderately colder than normal, was more than 11 percent colder in terms of heating degree-days than during the mild winter quarter of 2000. Weather contributed to the 11-percent growth distillate fuel oil demand compared to the same quarter last year. An additional factor was the change in relative prices brought about by the unprecedented spike in natural gas prices, which, in combination with the cold weather, helped boost residual fuel oil demand by 25 percent. Another factor was the concern about the possible impact of Y2K, which boosted deliveries in December, 1999, but depressed shipments in January, 2000.

Figure 11. Fossil Fuel Prices to Electric Utilities



Sources: History: EIA; Projections: Short-Term Energy Outlook, May 2001.

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U.S. natural gas demand is expected to grow at about a 1.9-percent rate this year, following the strong 4.9-percent performance in 2000 (Figure 14). A slowing economy and less rapid demand growth in the industrial and commercial sectors are the reasons. Growth in 2002 is expected to heat up to about 3.4 percent as the economy picks up again and as new gas-fired power generation requirements continue to mount.

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling experienced over the past year. Production is estimated to have risen by 3.7 percent in 2000 and it is forecast to continue to increase by 2.7 percent rate in 2001 and 2.5 percent in 2002.

Based on EIA survey data and recent information from the American Gas Association on early-season storage additions, we estimate that, on an EIA survey basis, working gas in storage at the end of April was 932 billion cubic feet (bcf) (Figure 15). It is a measure of the sensitivity of the gas market to developments this year concerning the progress of storage additions that recent spot prices and near futures have slipped to below $5.00 per thousand cubic feet (mcf) from recent peaks as high as $5.73 per mcf at the Henry Hub on April 11. The very large storage injections still expected for the summer may yet play a role in strengthening gas prices over the next few months, particularly if very hot temperatures and above-normal cooling demand appear in regions that use large amounts of gas for power generation and heightens the competition for gas between current and future demand sources.

Net imports of natural gas are projected to rise by about 13 percent in 2001 and by another 4 percent in 2002. For this summer, we project that natural gas imports will be 17 percent above last summer's as demand for storage refill is expected to be high.

Electricity Demand and Supply

Total annual electricity demand growth (retail sales plus industrial generation for own use) is projected at about 2.3 percent in 2001 and 2.1 percent in 2002. This is compared with estimated demand in 2000 that was 3.6 percent higher than the previous year's level. Electricity demand growth is expected to be slower in the forecast years than it was in 2000 partly because economic growth is also slowing from its higher 2000 level.

This summer's overall cooling degree-days (CDD) are projected to be normal, or about 1.0 percent below last summer's CDD total. Summer electricity demand is expected to be 2.6 percent higher than last summer based mainly on economic factors, i.e., rising GDP, albeit less rapid than last year, higher housing stocks and employment (Figure 16 and Table 10).

Hydropower generation in the crucial Pacific Northwest is expected to be down by 7.5 percent from last summer, due mainly to lower water levels. According to the National Oceanic and Atmospheric Association (NOAA), this winter was the second driest winter on record, after the 1976/77 winter. In addition, the crisis in California this winter has further drained reservoirs, depriving the region of generation resources for this spring and summer. Nuclear generation is also expected to be 5.6 percent lower than last summer mainly due to scheduled maintenance outages.

A total of 23,558 megawatts of new total electricity generating capacity was added in 2000. Based on accumulated public announcements (including wire reports, news articles and company press releases) over the past year, an estimated 40,000 to 50,000 megawatts of new capacity is planned for installation annually in 2001 and 2002. EIA's power plant surveys suggest that closer to 25,000 megawatts of new capacity will be installed annually in 2001 and in 2002. The table below shows the regional distribution of these capacity increases.

PRICE HEDGING REPORT

A Weekly Supplement to *Gas Daily*

Longs dispelled by shorts

The bears were on the prowl last week as the May contract neared expiration. Short positions dramatically increased, creating the reality of a deteriorating market. As summer begins to heat things up, though, prices could follow suit, sources say.

Short positions overtook long positions at an unusually large margin of more than three to one in the Commodity Futures Trading Commission's latest Commitments of Traders Report for the week ending April 24.

Short positions increased considerably last week, jumping to 14,524, compared to the prior week's report of 10,481. Long positions remained virtually unchanged coming in at 4,430 from last week's 4,137.

Spreading positions also increased slightly with the current report, showing 13,771, compared to the previous report of 13,630. Overall open interest increased to 388,716 from 385,794.

As the May contract approached expiration, a daily erosion of the screen began to take shape, sending prices below key support levels on Thursday and ultimately resulting in the May contract settling at $4.891 upon expiration.

The reason for the slump in prices appeared fundamentally based, as mild weather forecasts persist. In addition, a moderately bearish American Gas Association injection estimate also happened to coincide with the usual pre-expiration liquidations, adding fuel to the sell-off.

Even though the week ended with prices trending downward into the $4.80s, some traders believe that gas prices have possibly hit bottom for the rest of the year.

"A little over a week ago, $5 was considered an attractive buy, so now that we are below $5, we should begin to see a flurry of activity as the June contract begins to actively trade," a futures trader said.

"Summer heat is just around the corner, hurricane season begins in just a month from now, and to top it all off, we will be seeing a substantial increase in the number of gas-fired power generation plants coming online. It all adds up to the likelihood of higher prices to come, from what I can see," the trader said. AL

Commitments of Traders

This table shows long, short and spread positions of non-commercials, as reported weekly to the CFTC.

Rpt. Date	Long	Short	Spreading
24-Apr	4,430	14,524	13,771
17-Apr	4,137	10,471	13,630
10-Apr	5,908	7,693	11,911

Traders fear winter price repeat at Sumas

With traders coughing up more than $40/mmBtu for gas at Sumas, Wash., last December, players find themselves this spring attempting to hedge off any repeats of those bad memories.

One source said trying to determine what Sumas prices will do next winter is very difficult. "Weather and demand are big factors. And then there's the uncertainty of when Northwest Pipeline will call an operational flow order at Kemmerer, Wyo.," the source said.

He said constraints on northbound gas out of Wyoming on Northwest forced traders to buy Sumas gas last winter, helping drive the price up there. "That forced a lot of people to buy Sumas gas when they normally wouldn't buy there. If people try to shove gas through the constrained points like they did last year, we'll definitely see expensive gas again."

Because temperatures plunged so early last winter, there were strong storage draws in the Pacific Northwest and Rockies that led to storage worries for the rest of the season, another trader said. And California's power woes started around the same time.

"All of that combining is why we saw $40 gas," the source said. "If all that happens again, we'll see a return of $40 gas."

California's energy crisis will once again have an impact on Sumas price direction next winter, another source said. "If Southern California Gas goes to $40, Malin and Sumas will go there too. It's not just a point-by-point problem. It's a western region problem. A lot of these markets are connected."

To hedge themselves against that kind of volatility for the upcoming winter, most traders are working the November-to-March strip. "Sumas is trading at a small discount to Malin right now," one trader said. "Anywhere from 40¢ to $1.10 over the last few months."

Even though there is a certain spread, there is a big premium to the physical molecule in the wintertime. People trade financially to lock in positions, but if they want to convert to a physical position they pay big dollars, he added. "Physical molecules will create the Btus, not the financial paper," he explained.

Utilities have to make sure they are covered against the big price spikes too, no matter what factors enter the picture, a source said. "As a utility, we probably do more hedging than a marketer. We typically do it every year and not because of what happened last year at Sumas," the utility source said. SS

N. American rig count stable

After two weeks of big drops, the Canadian rig count stayed relatively flat last week at 188. The number of rigs exploring for oil and gas in Canada had dropped a total of 80 in the previous two reports released by Baker Hughes.

The U.S. rig count remained about the same, as well. The number of rigs exploring for oil and gas stood at 1,212 last week, down one from the previous count.

For all of North America, the oil and gas rig count dropped one to 1,400. RW

Henry Hub Futures and Strips

This table shows selected NYMEX Henry Hub contract settlement prices from the past week and calculates the 3-, 6-, 9-, and 12-month spreads. The chart to the right of the table data shows strip movement over the past 20 trading days. A dash indicates no data; an H indicates a holiday.

	04/23 Mon	04/24 Tue	04/25 Wed	04/26 Thu	04/27 Fri
May-01	5.125	5.078	4.981	4.891	-
Jun-01	5.175	5.114	4.994	4.940	4.867
Jul-01	5.240	5.177	5.057	5.002	4.935
Aug-01	5.298	5.232	5.110	5.055	4.990
Sep-01	5.310	5.245	5.125	5.070	5.010
Oct-01	5.338	5.275	5.155	5.102	5.045
Nov-01	5.482	5.420	5.300	5.252	5.198
Dec-01	5.618	5.562	5.450	5.402	5.354
Jan-02	5.672	5.617	5.507	5.462	5.415
Feb-02	5.512	5.462	5.357	5.317	5.275
Mar-02	5.242	5.205	5.115	5.086	5.050
Apr-02	4.792	4.749	4.665	4.646	4.620
3/strip	5.180	5.123	5.011	4.944	4.930
6/strip	5.248	5.187	5.070	5.010	5.007
9/strip	5.362	5.302	5.187	5.131	5.121
12/strip	5.317	5.261	5.151	5.102	5.022

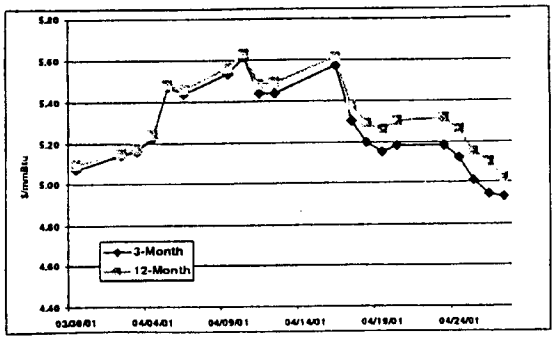

Exhibit No.____(RJL-15)
Docket No. UE-01_____
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Daily Price Survey continued

Trans. date	5/9	5/9	5/9
Flow date(s)	5/10	5/10	5/10
	Midpoint	Absolute	Common
New Mexico-San Juan Basin			
El Paso, Bondad	3.615	3.50-68	3.57-66
El Paso, non-Bondad	3.630	3.50-75	3.57-69
TW (Ignacio, pts south)	—	—	—
TW SJ (Blanco)	—	—	—
Rockies			
CIG (N. syst)	3.470	3.16-65	3.35-59
Kern River/Opal plant	3.610	3.38-74	3.52-70
NW, Stanfield	4.170	4.05-25	4.12-22
Questar	3.570	3.40-72	3.49-65
Cheyenne Hub	3.700	3.38-82	3.59-81
NW, Wyoming Pool	3.570	3.50-69	3.52-62
NW, south of Green River	3.465	3.15-65	3.34-59
Canadian Gas			
Iroquois	4.400	4.37-41	4.39-41
Niagara (NFG, Tenn)	4.395	4.37-43	4.38-41
NW Sumas	4.060	3.96-4.12	4.02-10
NOVA (AECO-C, NIT)*	C5.665	C5.62-69	C5.65-68
NOVA (same-day)*****	C5.635	5.58-68	5.61-66
Emerson (Viking/GL)	4.100	4.05-17	4.07-13
Dawn, Ont.	4.405	4.38-44	4.39-42
PG&E-GTNW (Kingsgate)	4.000	3.99-4.01	3.99-4.01
Westcoast, St. 2*	C5.745	C5.67-77	C5.72-77
Appalachia			
Dominion North Point	4.380	4.36-40	4.37-39
Dominion South Point	4.395	4.34-51	4.35-44
Columbia, App	4.345	4.29-43	4.31-38
Mississippi-Alabama			
FGT, Mobile Bay	4.025	4.00-05	4.01-04
Gulf South, Mobile Bay	3.990	3.95-4.03	3.97-4.01
Texas E., M-1 (Kosi)	4.235	4.20-27	4.22-25
Transco, St. 85	4.150	4.12-20	4.13-17
Others			
Algonquin	4.470	4.46-48	4.46-48
SoCal gas, large pkgs***	12.430	12.00-95	12.19-67
PG&E, large pkgs***	8.305	7.50-8.85	7.97-8.64
Kern River Station	—	—	—
Malin	4.605	4.25-95	4.43-78
Alliance (into Interstates)	4.205	4.18-24	4.19-22
ANR ML7 (entire zone)	4.405	4.36-49	4.37-44
NGPL Amarillo receipt	4.065	4.02-12	4.04-09
NGPL Iowa-Ill. receipt	4.095	4.03-16	4.06-13
Northern (Mid 13)	3.790	3.77-81	3.77-81
Northern (Ventura)	4.055	4.01-15	4.02-09
Northern (demarc)	4.050	4.00-15	4.01-09
Dracut (into TN)	4.335	4.30-44	4.30-37
Citygates			
Chicago-LDCs, large e-us	4.230	4.14-30	4.19-27
Mich.-Consum. Energy**	4.355	4.32-42	4.33-38
Mich.-Mich Con**	4.345	4.30-41	4.32-37
PSCo citygate	3.515	3.33-67	3.43-60
PG&E citygate	8.295	7.40-9.10	7.87-8.72
Northwest (all gates)	4.160	4.15-22	4.15-17
Florida gates via FGT	4.465	4.40-51	4.44-49
Algonquin citygates	4.505	4.42-56	4.47-54
Dominion (delivered)	4.580	4.57-59	4.57-59
Columbia Gas (delivered)	4.550	4.54-56	4.54-56
Tenn. zone 5	4.450	4.42-46	4.44-46
Tenn. zone 6 (delivered)	4.440	4.41-49	4.42-46
Iroquois, Zone 2	4.465	4.45-48	4.46-47
Texas E., M-3	4.490	4.41-60	4.44-54
Transco Z6 (non-NY)	4.480	4.41-60	4.43-53
Transco Z6 (NY)	4.515	4.45-62	4.47-56

NOTE: Price in C$ per gj; C$1=US$0.64918 (Canadian currency settlement from one business day prior EST.) **Large end-user prices. ***Deliveries into SoCal at Topock, Blythe, Needles, Ehrenburg; deliveries into PG&E at Topock and Daggett.*Volume-weighted for all points except AECO-C and Westcoast St. 2. *****The NOVA (same-day) midpoint and ranges are for flow on the transaction date.**

willingness to absorb both positive and negative financial performance."

In first quarter 2001, TransCanada's gas marketing operation took a major hit supplying gas under a contract with a Midwest utility that calls for lower than market prices. The effects of that contract and the costs of exiting the retail gas business caused the unit to record a C$6 million loss for the quarter. In the 2000 first quarter, the marketing unit reported C$10 million in earnings.

Gas marketing revenues grew by some C$4.5 billion in the first quarter compared to last year, mostly due to higher gas prices.

TransCanada said it had considered other options for the business, such as refocusing and downsizing, but decided it would be more valuable if it was divested as a going concern to "a more appropriate owner."

"We recognize our employees bring the most value to the gas marketing business, so we will negotiate with prospective buyers to maximize opportunities for these employees," Kvisle said. "We will work with all affected employees to ease their transition through the process." SGS

Low storage levels to keep gas prices high

Due to the low level of underground gas storage and strong demand for natural gas to fuel electricity generation, the Energy Information Administration expects gas prices to remain high until at least next year.

For this spring and summer, gas prices are projected to decline modestly. In 2001, annual gas prices will average more than $5, EIA stated in its Short-Term Energy Outlook. If the spring and summer are hot in regions that consume large quantities of gas, the injections into underground storage would again be strained, resulting in a rise in prices again next winter.

The outlook "reaffirm[s] the need to develop additional sources of energy while building and maintaining the necessary infrastructure to more those supplier to the market," said Energy Secretary Spencer Abraham. "Until we take steps to address these problems, we will continue to experience volatility in energy markets and higher prices passed on to consumers at the gas pump."

Domestic gas production for 2001 and 2002 is expected to rise as production responds to the high rates of drilling over the past year, EIA said. The growth rates are projected to be 2.7% in 2001 and 2.5% in 2002, compared to 3.7% in 2000.

Very large storage injections are still expected for this summer. The storage situation, said EIA, is expected to improve next year, however, driving prices down.

A slowing economy and less rapid demand growth in the industrial and commercial sectors would decrease the gas demand in 2001 to about 1.9%, as compared to the high growth rate of 4.9% seen in 2000. Growth in 2002 is expected to be about 3.4% as the economy picks up again.

Net imports for gas are projected to rise about 13% in 2001 and another 4% in 2002. For the coming summer season, EIA projected that gas imports will be 17% above last summer's as demand for storage refill is likely to be high. VK

BP chooses Tampa as site for LNG terminal

The city of Tampa, Fla., has the potential to become one of the great energy hubs in North America as the result of Gulfstream Natural Gas System coming onshore in the area as well as BP's plans to build a $200 million import terminal in the Port of Tampa, BP North America Gas and Power President Tony Fountain said yesterday at GasMart/Power in Tampa.

Crude oil and coal already have a strong presence in Tampa because of its major port. "As for us, we're very keen that this is going to become one of the great [liquefied natural gas] hubs.

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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-16)

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Cascade Natural Gas Receives Approval to Stabilize Rates

PR Newswire (November 02, 2001)

SEATTLE, Nov. 2 /PRNewswire/ -- Cascade Natural Gas Corporation (NYSE: CGC) received Washington Utilities and Transportation Commission (WUTC) approval for its Purchased Gas Cost Adjustment (PGA) and amortization of under-recovered gas cost from last winter filings. As a result of these two filings, Cascade's residential customers will see a net rate increase of 2.2%, 1.9% for the average commercial customer, and 2.1% for the average industrial customer, effective November 1, 2001. Cascade will recover last winter's gas cost over the next three years.

Jon Stoltz, Senior Vice President of Regulatory and Consumer Affairs stated, "In order to shield our customers from the price spikes that can occur in a volatile wholesale market, Cascade developed a strategy of locking in the quantity and price of the natural gas requirements of our customers for the next three years. By locking in the price of the supply, we can assure our customers that our rates will not significantly change and by locking in the quantity of supply, we can assure our customers that there will be adequate natural gas available to meet their needs. The fixed priced contracts will help us avoid an under-recovery situation similar to what occurred last winter."

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-17)

FINANCIAL TIMES Energy

Megawatt Daily's **Market Report**

Monday, December 11, 2000

Indexes and Transaction Record for 12/11/00

Explanations

Index — Volume-weighted average of all trades reported.
Absolute Low — Lowest trade reported.
Absolute High — Highest trade reported.
Trading Volume Reported — Volume of trades per hour for each of 16 peak hours. This figure is a total of all trading volume reported to MWD for each delivery site; because every effort is made to capture both sides of every deal reported, MWD recognizes that this figure includes duplicate volumes, and the figure should be used as a trend indicator not necessarily as an indicator for transmitted volumes.
Total Peak Volume — Volume for all peak hours, found by multiplying the trading volume by 16.
Number of Trades — This figure is calculated by dividing the trading volume reported by 50 MW/h for all Central and East listings; numbers of trades for delivery points in the West are calculated by dividing by 25 MW/h.

Methodology

The prices displayed in the table to the right are for power, in $/MWh, traded at the delivery points and regions listed. Peak hours are 0600-2200 hrs.; PJM and New York peak hours are 0700-2300. Off-peak hours generally start at 2200 hrs. on the date before the delivery date and end at 0600 on the delivery date. Not included are 24-hour deals categorized in some NERC regions as off-peak hours over Saturdays and Sundays. Transactions at the hubs listed in the separate table at the top of this page are financially firm. Deals at other locations may be unit-firm or system-contingent, and may include capacity reservation charges. Transactional data is gathered from utilities, marketers, co-ops, brokers, municipals and government power agencies. Deals done in the West are excluded if done after 1015 hrs. PT; deals done in the East and Central areas are excluded if done after 1100 hrs. CT. The middle column is the volume-weighted average of all deals reported and should be used for indexing purposes. The common range represents pricing for most of the trading volume; the absolute range represents lowest and highest prices reported. Copyright 2000 by Financial Times Energy.

Trades for Standard 16-Hour Daily Products; *all prices and volumes in $/MWh*

Delivery Point	Weighted Average Index	Absolute Low	Absolute High	Trading Volume Reported	All Peak Hours Volume	Number of Trades Reported
West						
COB	$3,000.00	$3,000.00	$3,000.00	25	400	1
Four C	—	—	—	0	0	0
Mead, Nev.	—	—	—	0	0	0
Mid-Columbia	$4,175.00	$3,000.00	$5,000.00	100	1,600	4
NP15	—	—	—	0	0	0
Palo Verde	$395.00	$360.00	$425.00	75	1,200	3
SP15	$350.00	$350.00	$350.00	25	400	1
Central						
ERCOT-B	$65.59	$60.00	$75.00	850	13,600	17
Ameren	—	—	—	0	0	0
Com Ed, into	$44.39	$40.00	$52.00	900	14,400	18
MAIN North	$63.33	$58.00	$120.00	300	4,800	6
MAIN South	—	—	—	0	0	0
MAPP North	$60.94	$50.00	$75.00	160	2,560	3
MAPP South	—	—	—	0	0	0
Entergy, into	$67.40	$50.00	$76.00	2,000	32,000	40
SPP	$65.90	$58.00	$75.00	500	8,000	10
East						
Cinergy	$48.47	$44.00	$53.00	6,550	104,800	131
North ECAR	$51.52	$45.00	$55.00	1,405	22,480	28
PJM-West	$49.01	$46.00	$54.00	2,800	44,800	56
Nepool	$74.00	$72.00	$80.00	500	8,000	10
NY Zone G	$67.50	$67.50	$67.50	200	3,200	4
NY Zone A	$57.85	$57.00	$59.00	600	9,600	12
NY Zone J	$81.00	$81.00	$81.00	50	800	1
VaCar	$46.00	$46.00	$46.00	150	2,400	3
Southern	$45.00	$45.00	$45.00	50	800	1
TVA, into	$43.92	$43.00	$47.00	1,200	19,200	24
Fla.-Ga.	$42.50	$40.00	$45.00	100	1,600	2
Fla. in-state	—	—	—	0	0	0

Trades for Standard Forward Products *(all prices in $/MWh)*

Delivery Point	Next Week 12/18 to 12/22		Balance of Month 12/12 to 12/31		Prompt Month 01/01				
	Low	High	Low	High	Low	High	Index	All pk. hrs. vol.	No. of Trades
West									
COB	—	—	—	—	—	—	—	0	0
Mid-Columbia	—	—	—	2,000.00	575.00	800.00	675.00	1,200	3
NP15	—	—	—	—	—	320.00	320.00	400	1
Palo Verde	—	—	—	—	250.00	375.00	300.00	1,200	3
SP15	—	—	—	—	—	—	—	0	0
Central									
Com Ed, into	—	75.00	—	68.00	—	—	—	0	0
Entergy, into	—	—	—	—	—	—	—	0	0
East									
Cinergy, into	72.00	85.00	—	70.00	—	—	—	0	0
PJM-West	—	—	—	61.00	—	—	—	0	0
NEPOOL	82.00	90.00	82.00	85.00	—	—	—	0	0
NY Zone G	—	—	—	—	—	—	—	0	0
NY Zone A	60.00	60.50	—	—	—	—	—	0	0
NY Zone J	—	—	—	—	—	—	—	0	0
TVA, into	—	66.00	—	—	—	—	—	0	0

Ranges and Indexes of Trades for Standard Off-Peak Products

Delivery Date: 12/11/00

	Wtd. Av. Index	Absolute Low	Absolute High	Trading Vol. Reported
West				
COB	—	—	—	0
Four C	$275.00	$275.00	$275.00	25
Mead, Nev.	—	—	—	0
Mid-C	$2,016.67	$1,550.00	$2,500.00	75
NP15	—	—	—	0
Palo Verde	$275.00	$275.00	$275.00	25
SP15	—	—	—	0
Central				
ERCOT-S	—	—	—	0
Ameren	—	—	—	0
Com Ed, into	$19.00	$19.00	$19.00	300
MAIN North	—	—	—	0
MAIN South	—	—	—	0
MAPP North	$21.00	$21.00	$21.00	125
MAPP South	$20.00	$20.00	$20.00	100
Entergy, into	—	—	—	0
SPP	$17.04	$13.00	$23.50	260
East				
Cinergy	—	—	—	0
North ECAR	$19.50	$19.00	$19.55	1,157
PJM-West	—	—	—	0
Nepool	—	—	—	0
NY Zone G	—	—	—	0
NY Zone A	—	—	—	0
NY Zone J	—	—	—	0
VaCar	—	—	—	0
Southern	—	—	—	0
TVA, into	—	—	—	0
Fla.-Ga.	$25.00	$25.00	$25.00	50
Fla. in-state	—	—	—	0

MGE, Alliant propose plant for university

A proposal between Madison Gas & Electric (MGE), Alliant Energy, the University of Wisconsin-Madison and Wisconsin's Department of Administration may result in a $170 million, 90- to 100-MW, natural gas-fired power plant on school ground that could solve a long-term energy crunch facing both the university and the city, the parties said last week.

If the plant gets all approvals necessary, the two utilities will jointly plan and oversee construction of the facility, which is anticipated to start in summer 2002. Plant operation is expected to begin in late 2003 or spring 2004.

Once construction is complete, MGE would own the facility with a third-party investor but would retain full operational control. Alliant will act as project manager. Although not a specified owner, Alliant will be paid for its services, company representative Chris Schoenherr said.

The proposed site at the university has the necessary infrastructure in place to support the facility, including electric transmission lines, a power substation and natural gas lines. MCM

Dailies scream to $5,000 at Mid-C, $3,000 at COB

The relentless upswing in next-day prices prevailed, with dailies trading to $5,000 at Mid-Columbia and $3,000 at COB.

"This is history," one source said. "Someone who buys power at that price [$5,000] is walking wounded. Actually, they're not even walking."

Western Markets

Overall, next-day volume was sparse. Deals arranged for today's delivery traded up to $425 at Palo Verde and near $350 at SP15.

In the bilateral market, off-peak for today traded near $275 at Palo Verde and at Four Corners.

The extreme pressure on prices carried over into the term markets, where balance-of-the-month sold for $2,000 at Mid-C and January there sold for $800 for a third consecutive day.

Crippled by idled power plants and tight energy imports, the state's power grid strained to meet the load going into the weekend. The danger of blackouts, caused by cold weather and an unprecedented drop in the energy supply, was expected to grow severely today, as an Arctic front blows down the West Coast from Canada.

Going into the weekend, California Power Exchange prices for Saturday peak were $251.23, with off-peak $256.79 and the 24-hour weighted average at $252.79. A day earlier, prices were fractions of a cent above $250.

The Bonneville Power Administration had no surplus power to sell at least through Saturday.

Friday began with a Stage 2 declaration by the California Independent System Operator — the fifth such declaration in as many days and the ninth in three weeks.

Also firming up power prices was the cost of natural gas, which reached as high as $63 at COB/Malin, Ore., $61 at the Pacific Gas & Electric Citygate and $55 at the Southern California Border.

At Palo Verde, January ranged $250-$375 and near $320 at NP15.

Second-quarter 2001 traded as high as $215 at Mid-C and in a tight range to $190 at Palo Verde.

Third-quarter 2001 sold at or above $290 at Palo Verde. KW/NM

Transmission problems force Entergy to mid $70s

Entergy dailies opened at $50, about $23 lower than the previous day's trades. However, they soon regained ground, passing the high from the day before.

By the end of the day deals were done at $76, a net gain of $1. Traders were not certain what was driving prices up, but suspected transmission constraints.

Central Markets

In MAIN, ComEd dailies fell even further, about $16 to the low $50s. Off-peak sold near $19.

Weekend trades moved in the low $30s and off-peak sold in the low $20s.

After undergoing a hot shutdown last week, ComEd's 828-MW nuke unit, Quad Cities 1, began powering back up after repairs.

Northern MAIN dailies moved around the low $60s. However, the same unfortunate player who all last week caught the high deals paid around $120 for a much-needed package. Weekend peak sold in the upper $20s.

Ameren reported weekend off-peak deals near $20.

Light weekend demand helped push northern MAPP dailies down about $20, to $75.

Central Generation Outage Report for December 11

Information from the Nuclear Regulatory Commission is sometimes outdated, and not all utilities respond to requests for verification of unit status. Copyright 2000 by FT Energy

Unit Name, Operator	MW	NERC Region	Unit Status	Scheduled restart or outage date
LaSalle 2 ComEd	828	MAIN	Nuclear; operating at 100% following Oct. 6 refueling outage	Full power Dec. 8
Quad Cities 1 ComEd	828	MAIN	Nuclear; operating at 1% after hot shutdown Dec. 6	Start up on Dec. 7

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-18)

Avista Corporation
2001 Load and Estimated Variability

	Avg (aMW)	Jan (aMW)	Feb (aMW)	Mar (aMW)	Apr (aMW)	May (aMW)	Jun (aMW)	Jul (aMW)	Aug (aMW)	Sep (aMW)	Oct (aMW)	Nov (aMW)	Dec (aMW)
Average Load [1]	965.1	1,147.0	1,108.9	975.4	906.6	861.9	867.7	911.1	956.5	864.0	910.4	1,001.0	1,078.0
80% CI [2]	43.5	86.9	67.6	40.4	36.1	12.3	35.5	39.0	45.7	20.6	33.2	49.0	56.5
95% CI [2]	67.3	134.5	104.7	62.5	55.8	19.0	54.9	60.4	70.8	31.9	51.5	75.8	87.4

[1] Jan-Oct actuals including full Potlatch load, Nov-Dec values are estimated with 93 aMW of Potlatch lad

[2] average of weekly weekly confidence interval values

Exhibit No.____(RJL-18)
Docket No. UE-01_____
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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-22)

AVISTA Corp.

Energy Resources

Date: December 4, 2000

To: Jim Jewell/Jerry Parmentier/Tim Carlberg/Bob Lafferty/Steve Wenke/Clint Kalich

From: Bill Johnson

Subject: Rates of Return on Investment to Operate Northeast Additional Hours

I've calculated returns on a $3 million investment in pollution control equipment for Northeast combustion turbine. The premise of the analysis is that the investment in the pollution control equipment will increase the hours we can operate the turbine from 500 hours per year to at least 3,000 hours per year. I valued the increased generation in two ways, 1) as the value of increased generation, and 2) as the value of the turbine as on option with a strike price at the incremental fuel cost. For increased generation, Clint built a model to optimize the plant for 500 hours of operation and for 3,000 hours. The value is the increased margins for 3,000 hours of operation versus 500 hours of operation. The option value of the plant is based on a $15/MWh premium in the first year that decreases to less than $6/MWh in the 10th year as market prices decrease relative to the plants incremental fuel cost. Both analyses assume a 10-year life.

The analysis indicates that the plant would generate margins primarily in the July through December period. If we were to construct additional generation at the Northeast site, then the value of additional generation would decrease due to transmission limitations during summer months.

The results are shown below. Supporting workpapers are attached.

	Increased Energy	Option Value
Rate of Return	42%	49%

AVI. CORP

NORTHEAST TURBINE ADDITIONAL HOURS ANALYSIS - ~~WATER INJECTION~~ Dry Low NOx

Capital Cost	$3,000,000
Additional Hours of Operation	2,500
2001 Flat Price	$68.73
2001 Call Value $/MWh	$15

Reduces to $5.81/MWh in 2010

Period	Date	Revenues	Incremental O&M	Property Taxes	Tax Depreciation Expense	Income Tax Expense	Capital Expenditure	After-tax Cash Flows	Present Value ATCF	Cumulative PV ATCF	Incremental IRR	Revenue Requirements	Incremental Revenue Requirements
SUM		12,700,770	2,800,845	422,970	3,000,000	2,266,934	3,000,000	4,210,020	2,360,118			10,423,183	-2,277,588
NPV		7,698,465	1,657,733	250,989	1,680,222	1,853,698	2,762,685	2,360,118				5,785,718	-3,099,506
LEV		700,448	150,830	22,836	152,876	168,660	251,364	214,736				584,874	-313,327
ESC							Discounted Payback:		2.94	IRR:	48.60%		
0	2000											0	0
1	2001	1,950,000	0	41,240	150,000	615,566	3,000,000	-1,706,806	-1,571,789	-1,571,789	#NUM!	530,055	-1,419,945
2	2002	1,755,000	250,000	39,125	285,000	413,306	0	1,052,569	892,629	-679,160	-38.33%	847,745	-907,255
3	2003	1,579,500	256,250	37,010	256,500	360,409	0	925,831	723,040	43,880	10.68%	825,466	-754,034
4	2004	1,421,550	262,656	34,895	231,000	312,550	0	811,449	583,582	627,462	30.87%	804,658	-616,892
5	2005	1,279,395	269,223	32,780	207,900	269,322	0	708,070	468,950	1,096,412	39.89%	785,195	-494,200
6	2006	1,151,456	275,953	30,665	186,900	230,278	0	614,559	374,822	1,471,234	44.25%	766,973	-384,483
7	2007	1,036,310	282,852	28,550	177,000	191,768	0	533,140	299,442	1,770,676	46.49%	749,675	-286,635
8	2008	932,679	289,923	26,436	177,000	153,762	0	462,558	239,248	2,009,923	47.69%	732,798	-199,881
9	2009	839,411	297,171	24,321	177,300	119,217	0	398,702	189,907	2,199,830	48.35%	716,099	-123,312
10	2010	755,470	304,601	22,206	177,000	88,082	0	340,581	149,390	2,349,220	48.71%	699,590	-55,880

WGJ
10-12-2000

AVIS CORP

NORTHEAST TURBINE ADDITIONAL HOURS ANALYSIS - ~~WATER INJECTION~~ Dry Low NO_x

Capital Cost	$3,000,000
Additional Hours of Operation	2,500
2001 Flat Price	$52.38

Period	Date	Incremental Revenues	Incremental O&M	Property Taxes	Tax Depreciation Expense	Income Tax Expense	Capital Expenditure	After-tax Cash Flows	Present Value ATCF	Cumulative PV ATCF	Incremental IRR	Revenue Requirements	Incremental Revenue Requirements
SUM		71,515,641	56,591,703	422,970	3,000,000	4,025,339	3,000,000	7,475,629	3,891,119			66,790,241	-4,725,401
NPV		45,753,996	36,518,386	250,989	1,680,222	2,678,083	2,762,685	3,891,119				42,315,949	-3,785,314
LEV		4,162,947	3,322,641	22,836	152,876	243,667	251,364	354,035				4,277,692	-382,655
ESC							Discounted Payback:		3.66	IRR:	41.96%		
0	2000											0	0
1	2001	4,307,365	3,695,391	41,240	150,000	147,257	3,000,000	-2,576,523	-2,372,707	-2,372,707	#NUM!	4,402,429	95,064
2	2002	8,263,211	6,563,093	39,125	285,000	481,598	0	1,179,396	1,000,184	-1,372,523	#NUM!	7,463,191	-800,021
3	2003	7,666,762	6,094,115	37,010	256,500	447,698	0	1,087,939	849,640	-522,883	-8.22%	6,942,923	-723,839
4	2004	7,616,668	6,010,006	34,895	231,000	469,268	0	1,102,498	792,900	270,017	14.92%	6,827,265	-789,403
5	2005	6,984,331	5,165,333	32,780	207,900	552,411	0	1,233,807	817,143	1,087,160	27.87%	5,915,794	-1,068,537
6	2006	7,171,833	5,392,717	30,665	186,900	546,543	0	1,201,908	733,048	1,820,208	34.61%	6,128,793	-1,043,040
7	2007	6,954,147	5,608,143	28,550	177,000	399,159	0	918,295	515,767	2,335,975	37.63%	6,330,009	-624,138
8	2008	7,326,828	5,830,937	26,436	177,000	452,359	0	1,017,096	526,070	2,862,045	39.72%	6,539,187	-787,641
9	2009	7,657,489	6,019,073	24,321	177,300	502,878	0	1,111,217	529,286	3,391,331	41.15%	6,712,039	-945,450
10	2010	7,567,007	6,212,896	22,206	177,000	404,217	0	927,688	406,915	3,798,246	41.93%	6,890,851	-676,156

WGJ
10-12-2000

Exhibit No.____(RJL-22)
Docket No. UE-01____
Page 3 of 7

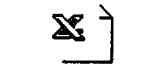
Month	Hours			Market Prices			Operating Cost	Hours Operated			
	HLH	LLH	Total	HLH ($/MWh)	LLH ($/MWh)	Gas ($/dth)	($/MWh)	HLH	LLH	Total	Ann. Total
Jan-01	424	320	744	61.3	41.8	3.557	52.8	0.0	0.0	0.0	
Feb-01	383	289	672	61.4	41.3	3.557	52.8	0.0	0.0	0.0	
Mar-01	424	320	744	70.3	47.3	3.557	52.8	0.0	0.0	0.0	
Apr-01	410	309	719	45.7	29.5	3.557	52.8	0.0	0.0	0.0	
May-01	424	320	744	41.4	23.9	3.557	52.8	0.0	0.0	0.0	
Jun-01	410	310	720	41.4	24.6	3.557	52.8	0.0	0.0	0.0	
Jul-01	424	320	744	63.9	31.2	3.557	52.8	0.0	0.0	0.0	
Aug-01	424	320	744	112.1	41.6	3.557	52.8	0.0	0.0	0.0	
Sep-01	410	310	720	85.6	46.6	3.557	52.8	410.4	0.0	410.4	
Oct-01	425	320	745	60.4	36.6	3.557	52.8	424.7	0.0	424.7	
Nov-01	410	310	720	65.4	44.2	3.557	52.8	410.4	0.0	410.4	
Dec-01	424	320	744	59.3	41.4	3.557	52.8	424.1	0.0	424.1	1,669.5
Jan-02	424	320	744	47.2	32.9	2.910	43.8	424.1	0.0	424.1	
Feb-02	383	289	672	47.1	32.8	2.910	43.8	0.0	0.0	0.0	
Mar-02	424	320	744	47.2	35.6	2.910	43.8	58.2	0.0	58.2	
Apr-02	410	309	719	36.8	26.2	2.910	43.8	0.0	0.0	0.0	
May-02	424	320	744	33.6	21.6	2.910	43.8	0.0	0.0	0.0	
Jun-02	410	310	720	34.8	21.5	2.910	43.8	0.0	0.0	0.0	
Jul-02	424	320	744	53.9	28.3	2.910	43.8	424.1	0.0	424.1	
Aug-02	424	320	744	63.2	36.2	2.910	43.8	424.1	0.0	424.1	
Sep-02	410	310	720	65.9	41.6	2.910	43.8	410.4	0.0	410.4	
Oct-02	425	320	745	52.3	33.7	2.910	43.8	424.7	0.0	424.7	
Nov-02	410	310	720	59.7	39.2	2.910	43.8	410.4	0.0	410.4	
Dec-02	424	320	744	57.1	39.5	2.910	43.8	424.1	0.0	424.1	3,000.0
Jan-03	424	320	744	42.4	30.4	2.682	40.7	0.0	0.0	0.0	
Feb-03	383	289	672	42.5	30.4	2.682	40.7	58.2	0.0	58.2	
Mar-03	424	320	744	44.3	32.7	2.682	40.7	424.1	0.0	424.1	
Apr-03	410	309	719	32.8	24.7	2.682	40.7	0.0	0.0	0.0	
May-03	424	320	744	30.1	20.4	2.682	40.7	0.0	0.0	0.0	
Jun-03	410	310	720	30.5	19.9	2.682	40.7	0.0	0.0	0.0	
Jul-03	424	320	744	49.3	25.2	2.682	40.7	424.1	0.0	424.1	
Aug-03	424	320	744	57.1	31.4	2.682	40.7	424.1	0.0	424.1	
Sep-03	410	310	720	61.2	36.6	2.682	40.7	410.4	0.0	410.4	
Oct-03	425	320	745	48.4	30.2	2.682	40.7	424.7	0.0	424.7	
Nov-03	410	310	720	56.3	36.5	2.682	40.7	410.4	0.0	410.4	
Dec-03	424	320	744	53.9	37.5	2.682	40.7	424.1	0.0	424.1	3,000.0
Jan-04	424	320	744	40.7	29.6	2.704	41.1	0.0	0.0	0.0	
Feb-04	397	299	696	34.0	25.8	2.704	41.1	0.0	0.0	0.0	
Mar-04	424	320	744	41.5	30.8	2.704	41.1	424.1	0.0	424.1	
Apr-04	410	309	719	31.7	24.5	2.704	41.1	0.0	0.0	0.0	
May-04	424	320	744	27.9	20.5	2.704	41.1	0.0	0.0	0.0	
Jun-04	410	310	720	32.8	20.6	2.704	41.1	0.0	0.0	0.0	
Jul-04	424	320	744	49.6	26.6	2.704	41.1	424.1	0.0	424.1	
Aug-04	424	320	744	72.4	32.2	2.704	41.1	424.1	0.0	424.1	
Sep-04	410	310	720	67.1	36.1	2.704	41.1	410.4	0.0	410.4	
Oct-04	425	320	745	49.8	32.3	2.704	41.1	424.7	0.0	424.7	

Month	Hours			Market Prices			Operating Cost ($/MWh)	Hours Operated			
	HLH	LLH	Total	HLH ($/MWh)	LLH ($/MWh)	Gas ($/dth)		HLH	LLH	Total	Ann. Total
Nov-04	410	310	720	54.2	37.2	2.704	41.1	410.4	0.0	410.4	
Dec-04	424	320	744	53.0	39.2	2.704	41.1	424.1	0.0	424.1	2,941.8
Jan-05	424	320	744	42.3	29.9	2.817	42.8	0.0	0.0	0.0	
Feb-05	383	289	672	41.5	30.4	2.817	42.8	0.0	0.0	0.0	
Mar-05	424	320	744	42.5	31.4	2.817	42.8	0.0	0.0	0.0	
Apr-05	410	309	719	33.0	25.1	2.817	42.8	0.0	0.0	0.0	
May-05	424	320	744	29.6	21.4	2.817	42.8	0.0	0.0	0.0	
Jun-05	410	310	720	34.6	21.3	2.817	42.8	0.0	0.0	0.0	
Jul-05	424	320	744	52.2	27.6	2.817	42.8	424.1	0.0	424.1	
Aug-05	424	320	744	89.3	33.0	2.817	42.8	424.1	0.0	424.1	
Sep-05	410	310	720	75.3	36.7	2.817	42.8	410.4	0.0	410.4	
Oct-05	425	320	745	52.3	33.3	2.817	42.8	424.7	0.0	424.7	
Nov-05	410	310	720	56.8	38.4	2.817	42.8	410.4	0.0	410.4	
Dec-05	424	320	744	55.6	40.3	2.817	42.8	424.1	0.0	424.1	2,517.7

Emerson, John

From: Emerson, John
Sent: Monday, December 04, 2000 5:17 PM
To: Brukardt, David; Burmeister-Smith, Christy; Eliassen, Jon; Ely, Gary; Emerson, John; Gorton, Pat; Groce, Ed; Hemstrom, Steve; Hubbard, Dale; Jenkins, Thomas; Jewell, Jim; Mattern, Kim; Morris, Scott; Norwood, Kelly; Payne, William; Peterson, Ron; Steiner, Nolan; Stevens, Rich; Storro, Dick; Thackston, Jason
Subject: Position Report

Purchases and Sales: Prices for pre-scheduled load for Tuesday were about $270 for heavy and $220 for light. For Tuesday, we were a net purchaser of 25 aMW heavy load. A change to Clark Fork December streamflows due to an unscheduled storage water release from Kerr is being analyzed. The estimated impact of this change will be an increase in resources of 55 aMW on peak. A decrease in storage water in Q1 2001 will also be involved, most likely in March. These changes have not been reflected in today's report--they will be included later this week.



Dec0400position.xls

Hydro:
Colstrip: Both units running.
Rathdrum: Both units running.
Northeast Combustion Turbine: Down for combustion inspection and maintenance. Expected back Friday Dec 8 PM.
Loads:
Prices:

4-Dec	Heavy Load Mid C Prices	Light Load Mid C Prices	Gas Prices @ Dec 4	Marginal Rathdrum Thermal Cost
Real-Time	$ 260.00	$ 205.00		
Dec - Next Day	$ 270.00	$ 220.00	$ 20.00	$ 241.02
Dec - Balance	$ 650.00	$ 230.00	$ 20.00	$ 241.02
January	$ 580.00	$ 220.00	$ 16.93	$ 204.18
February	$ 315.00	na	$ 11.54	$ 139.50
Q1 2001	$ 362.50	$ 157.50	$ 12.53	$ 151.38
Q2 2001	$ 187.50	$ 110.00	$ 7.60	$ 92.22
Q3 2001	$ 250.00	$ 130.00	$ 7.33	$ 88.98
Q4 2001	$ 145.00	$ 56.00	$ 6.99	$ 84.90
Calendar 2001	$ 236.25	$ 113.38		

1-Dec	Heavy Load Mid C Prices	Light Load Mid C Prices	Gas Prices @ Nov 27	Marginal Rathdrum Thermal Cost
Real-Time	$ 250.00	$ 200.00		
Dec - Next Day	$ 270.00	$ 220.00	$ 14.00	$ 169.02
Dec - Balance	$ 312.50	$ 230.00	$ 14.25	$ 172.02
January	$ 275.00	$ 220.00	$ 10.50	$ 127.02
February	$ 220.00	na	$ 8.50	$ 103.02
Q1 2001	$ 215.00	$ 157.50	$ 8.05	$ 97.62
Q2 2001	$ 126.00	$ 110.00	$ 5.80	$ 70.62
Q3 2001	$ 202.00	$ 130.00	$ 5.70	$ 69.42
Q4 2001	$ 223.00	$ 56.00	$ 5.60	$ 68.22
Calendar 2001	$ 191.50	$ 113.38		

Avis Utilities

Position Report

December 4, 2000

fidential

Month & Hours	Index Purchase (Sale) (a)	Physical Position Long (Short) (b)	Financial Put (Call) et Delta "(c)"	Total Position Long (Short) (d)	Rath Turb Inc in Phy Fuel Pur	Rathdrum Turb. Fuel Not Pur (e)	Physical Open Position (f)	Financial Open Position (g)	Financial Quarter Average	Fin & NG Open Position (h)	Month Short Limit	Month Long Limit	Fin & NG Quarter Average	Quarter Short Limit	Quarter Long Limit
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Dec HL	(5)	22	0	22	168	0	22	27		27	0	150			
Dec LL	(5)	(4)	0	(4)	162	0	(4)	1		1	0	150			
Jan HL	(5)	70	0	70	160	0	70	75		75	(75)	200			
Jan LL	(5)	32	0	32	160	0	32	37		37	(75)	200			
Feb HL	(5)	23	0	23	160	0	23	28	19	28	(75)	200	19	(25)	150
Feb LL	(5)	37	0	37	80	0	37	42	25	42	(75)	200	25	(25)	150
Mar HL	(5)	(52)	0	(52)	80	0	(52)	(47)		(47)	(75)	200			
Mar LL	(5)	(8)	0	(8)	80	0	(8)	(3)		(3)	(75)	200			
Apr HL	(5)	(68)	0	(68)	80	40	(28)	(23)		(63)	(150)	250			
Apr LL	(5)	(133)	0	(133)	0	80	(53)	(48)		(128)	(150)	250			
May HL	(5)	51	0	51	0	0	51	56	24	56	(150)	250	10	(50)	150
May LL	(5)	192	0	192	0	0	192	197	131	197	(150)	250	104	(50)	150
Jun HL	(5)	34	0	34	80	0	34	39		39	(150)	250			
Jun LL	(5)	238	0	238	0	0	238	243		243	(150)	250			
Jul HL	(5)	175	0	175	150	0	175	180		180	(150)	250			
Jul LL	(5)	(15)	0	(15)	150	0	(15)	(10)		(10)	(150)	250			
Aug HL	5	(73)	0	(73)	150	0	(73)	(78)	38	(78)	(150)	250	38	(50)	150
Aug LL	5	(27)	0	(27)	150	0	(27)	(32)	(5)	(32)	(150)	250	(5)	(50)	150
Sep HL	(5)	6	0	6	155	0	6	11		11	(150)	250			
Sep LL	(5)	23	0	23	155	0	23	28		28	(150)	250			
Oct HL	(5)	(47)	0	(47)	160	0	(47)	(42)		(42)	(150)	250			
Oct LL	(5)	57	0	57	160	0	57	62		62	(150)	250			
Nov HL	(5)	60	0	60	160	0	60	65	33	65	(150)	250	33	(50)	150
Nov LL	(5)	67	0	67	160	0	67	72	45	72	(150)	250	45	(50)	150
Dec HL	(5)	72	0	72	160	0	72	77		77	(150)	250			
Dec LL	(5)	(5)	0	(5)	160	0	(5)	(0)		(0)	(150)	250			

Month & Hours	Hrs	Impact of $10 Increase in Prices
Dec HL	400	$ 109,457
Dec LL	344	$ 3,683
Jan HL	416	$ 313,560
Jan LL	328	$ 122,258
Feb HL	384	$ 107,154
Feb LL	288	$ 119,640
Mar HL	432	$ (204,871)
Mar LL	312	$ (10,733)
Apr HL	400	$ (93,145)
Apr LL	320	$ (153,281)
May HL	416	$ 232,088
May LL	328	$ 644,601
Jun HL	416	$ 161,224
Jun LL	304	$ 738,530
Jul HL	400	$ 721,977
Jul LL	344	$ (35,729)
Aug HL	432	$ (338,580)
Aug LL	312	$ (100,620)
Sep HL	384	$ 41,256
Sep LL	336	$ 93,648
Oct HL	432	$ (183,214)
Oct LL	312	$ 194,053
Nov HL	400	$ 260,202
Nov LL	320	$ 231,467
Dec HL	400	$ 306,957
Dec LL	344	$ (617)

Footnotes:

(a) Index transactions are already included in the total physical position.

(b) Physical position.

(c) Aggregate physical equivalent (delta) position of options (put and calls).

(d) Total position is the combined physical and delta positions.

(e) Turbines in this column are available for use, but gas has not been purchased.
When gas is purchased for turbines, the equivalent megawatts are reflected in the L&R and removed from this column.

(f) Open physical position includes total position and available turbines.

(g) Open financial position includes open physical position less any index position.

(h) Open financial and natural gas position includes open financial position less Rathdrum fuel not purchased.

Exhibit No.____(RJL-22)
Docket No. UE-01_____
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BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-23)

AVISTA Corporation

FILE
KETTLE FALLS
CT
PROJECT

Interoffice Memorandum
Energy Resources

DATE: February 14, 2001

TO: Thomas Dempsey

FROM: Steve Silkworth

SUBJECT: Kettle Falls CT Installation – Revised Economic Evaluation

Thomas – Attached to this memo are the revised economic evaluation results for the proposed combustion turbine addition to the Kettle Falls site. I revised this memo to reflect the economics based upon actual forward market strip prices for electricity and natural gas. In the previous analysis, I used the same price forecast that was prepared by RW Beck consultants for the recent Request for Proposal evaluation. This forecast is 12 weeks old and does not capture recent upswing in the spark spreads.

For easy reference, also attached is a spreadsheet with the annual electric and natural gas prices used in the evaluation.

Three Cases Analyzed:

1. Simple cycle only
2. Simple cycle with HRSG and steam sent to feedwater heater in KFGS
3. Combined cycle with Staco mini-steam turbine, steam then sent to DA.

Economics

The project economics was evaluated by the method used in Avista's recent Request for Proposal process. This method consisted of:

- Forward strip electric and natural gas prices through 2007 then hourly electric and monthly natural gas price forecast provided by RW Beck through 2025.
- Dispatch of the machine was calculated on an hourly basis by using the Prosym production cost model from February 2002 to December 2025.
- Plant characteristics such as heat rate, VOM and O&M costs, planned maintenance, and capital costs were provided by the Generation and Production department.
- All other costs were modeled consistent with the company's Standard Assumptions Manual and revenue requirements model.

Economic Results (2001 $'s)

	Net Benefit Nominal Levelized $/MWh	Net Benefit Real Levelized $/MWh	Net Present Value $ (000's)
1. Simple Cycle Only	12.5	9.8	3,151
2. Simple cycle with HRSG and steam sent to feedwater heater	16.1	12.6	10,601
3. Combined cycle with Staco mini-steam turbine, steam then sent to DA	15.1	11.8	11,258

The results indicate that in all cases, the project returns a positive present value. In other words, each of the cases are lower in cost than equivalent market purchases over the project lives. Cases 2 and 3 have a payback of approximately three years.

If you have any questions, please call me on extension 8093.

Distribution:
Ed Groce
Clint Kalich
Jason Thackston
Jerry Parmentier
Steve Wenke

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	10,000	$000s	
Project Capacity	9.8	MW	
Heat Rate	8,750	Btu/kWh	
Peak Gas Useage	2,048	000s dth	
Fixed Charge	0.00	per kW-month	
Fixed O&M	0.00	2003$ per kW-month	
Escalation Rates			
Fixed O&M	2.5	percent	
Variable O&M	2.5	percent	
Transportation	2.0	percent	
Variable O&M	2.00	2001$/MWh	
Insurance Cost	0.0	0.3% of installed cost ($000s)	
Gas Transport	0.00	2000 $/dth	
Electric Wheeling	0	$/MW-month thru 2006	
General Inflation	2.5	percent	
Electric Wheeling Losses	1.9	percent	
Nominal Discount Rate	7.8	percent	
Real Discount Rate	5.1	percent	

Row		Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Fixed Costs – Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
18	1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
19	2	2002	71.9	1,766	0	1,766	24.6	0	0	0	136	0	136	1.9
20	3	2003	77.6	1,700	0	1,700	21.9	0	0	0	132	0	132	1.7
21	4	2004	75.9	1,635	0	1,635	21.6	0	0	0	127	0	127	1.7
22	5	2005	70.6	1,565	0	1,565	22.2	0	0	0	122	0	122	1.7
23	6	2006	62.1	1,495	0	1,495	24.1	0	0	0	117	0	117	1.9
24	7	2007	56.8	1,433	0	1,433	25.2	0	0	0	113	0	113	2.0
25	8	2008	75.9	1,373	0	1,373	18.1	0	0	0	108	0	108	1.4
26	9	2009	75.9	1,329	0	1,329	17.5	0	0	0	103	0	103	1.4
27	10	2010	76.6	1,286	0	1,286	16.8	0	0	0	99	0	99	1.3
28	11	2011	76.7	1,243	0	1,243	16.2	0	0	0	94	0	94	1.2
29	12	2012	76.4	1,201	0	1,201	15.7	0	0	0	89	0	89	1.2
30	13	2013	75.6	1,157	0	1,157	15.3	0	0	0	85	0	85	1.1
31	14	2014	75.4	1,114	0	1,114	14.8	0	0	0	80	0	80	1.1
32	15	2015	75.1	1,073	0	1,073	14.3	0	0	0	75	0	75	1.0
33	16	2016	74.8	1,031	0	1,031	13.8	0	0	0	70	0	70	0.9
34	17	2017	73.7	987	0	987	13.4	0	0	0	66	0	66	0.9
35	18	2018	73.2	944	0	944	12.9	0	0	0	61	0	61	0.8
36	19	2019	71.9	899	0	899	12.5	0	0	0	56	0	56	0.8
37	20	2020	69.8	854	0	854	12.2	0	0	0	52	0	52	0.7
38	21	2021	68.1	809	0	809	11.9	0	0	0	47	0	47	0.7
39	22	2022	66.4	769	0	769	11.6	0	0	0	42	0	42	0.6
40	23	2023	66.3	742	0	742	11.2	0	0	0	38	0	38	0.6
41	24	2024	65.5	719	0	719	11.0	0	0	0	33	0	33	0.5
42	25	2025	65.3	696	0	696	10.7	0	0	0	28	0	28	0.4
44	2001$													
45	Net Present Value			13,141	0	13,141		0	0	0	979	0	979	
46	Nominal Levelized Cost ($/MWh)						17.6							1.3
47	Real Levelized Cost ($/MWh)						13.8							1.0

Row	Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
18	2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
19	2002	1,902	1,902	26.5	7,338	5,436	75.6	3,472	148	3,619	50.3	5,522	76.8
20	2003	1,832	1,832	23.6	4,147	2,316	29.8	3,163	163	3,326	42.9	5,158	66.5
21	2004	1,762	1,762	23.2	2,816	1,053	13.9	3,015	164	3,179	41.9	4,941	65.1
22	2005	1,687	1,687	23.9	2,087	400	5.7	2,721	156	2,878	40.8	4,565	64.7
23	2006	1,613	1,613	26.0	1,386	(228)	(3.7)	2,400	141	2,541	40.9	4,154	66.9
24	2007	1,546	1,546	27.2	1,048	(497)	(8.7)	2,187	133	2,319	40.8	3,865	68.0
25	2008	1,481	1,481	19.5	1,782	300	4.0	1,931	182	2,113	27.9	3,594	47.4
26	2009	1,432	1,432	18.9	1,816	383	5.1	2,004	186	2,191	28.9	3,623	47.7
27	2010	1,385	1,385	18.1	1,880	496	6.5	2,087	193	2,280	29.9	3,675	48.0
28	2011	1,337	1,337	17.4	1,893	556	7.2	2,183	198	2,381	31.1	3,718	48.5
29	2012	1,290	1,290	16.9	2,117	827	10.8	2,265	203	2,468	32.3	3,758	49.2
30	2013	1,241	1,241	16.4	1,857	616	8.2	2,329	206	2,535	33.6	3,776	50.0
31	2014	1,194	1,194	15.8	1,894	700	9.3	2,426	211	2,637	35.0	3,831	50.8
32	2015	1,148	1,148	15.3	1,860	712	9.5	2,532	215	2,747	36.6	3,896	51.9
33	2016	1,101	1,101	14.7	1,844	742	9.9	2,636	220	2,856	38.2	3,957	52.9
34	2017	1,053	1,053	14.3	1,824	771	10.5	2,709	222	2,931	39.8	3,984	54.1
35	2018	1,006	1,005	13.7	1,824	819	11.2	2,793	227	3,020	41.3	4,025	55.0
36	2019	958	956	13.3	1,783	827	11.5	2,842	228	3,070	42.7	4,026	56.0
37	2020	905	905	13.0	2,094	1,189	17.0	2,870	227	3,097	44.4	4,002	57.4
38	2021	856	856	12.6	2,066	1,211	17.8	2,918	228	3,146	46.2	4,002	58.8
39	2022	811	811	12.2	2,035	1,224	18.4	2,958	228	3,186	48.0	3,997	60.2
40	2023	780	780	11.8	2,008	1,228	18.5	3,076	233	3,309	49.9	4,089	61.7
41	2024	752	752	11.5	2,009	1,257	19.2	3,175	236	3,412	52.1	4,184	63.8
42	2025	726	726	11.1	1,968	1,242	19.0	3,300	242	3,542	54.2	4,268	65.4
45	Net Present Value	14,120	14,120		25,378	11,258		26,334	1,835	28,170		42,290	
46	Nominal Levelized Cost ($/MWh)			18.9			15.1				37.7		56.6
47	Real Levelized Cost ($/MWh)			14.8			11.8				29.5		44.3

Exhibit No._____(RJL-23)

Docket No. UE-01_____

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	8,500	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00	2001$/MWh	Electric Wheeling Losses	1.9 percent
Project Capacity	9.5	MW	Fixed O&M	0.00	2003$ per kW-month					
Heat Rate	8,750	Btu/kWh	Escalation Rates			Insurance Cost	0.0	0.3% of installed cost ($000s)	Nominal Discount Rate	7.8 percent
Peak Gas Useage	1,995	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00	2000 $/dth	Real Discount Rate	5.1 percent
			Variable O&M	2.5	percent	Electric Wheeling	0	$/MW-month thru 2006		
			Transportation	2.0	percent	General Inflation	2.5	percent		

Fixed Costs

	Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!
2	2002	63.3	1,506	0	1,506	23.8
3	2003	68.3	1,450	0	1,450	21.2
4	2004	66.7	1,394	0	1,394	20.9
5	2005	62.1	1,334	0	1,334	21.5
6	2006	54.7	1,275	0	1,275	23.3
7	2007	49.9	1,221	0	1,221	24.5
8	2008	66.8	1,170	0	1,170	17.5
9	2009	66.8	1,133	0	1,133	17.0
10	2010	67.4	1,097	0	1,097	16.3
11	2011	67.4	1,060	0	1,060	15.7
12	2012	67.2	1,024	0	1,024	15.2
13	2013	66.4	987	0	987	14.9
14	2014	66.3	951	0	951	14.3
15	2015	66.1	916	0	916	13.9
16	2016	65.8	880	0	880	13.4
17	2017	64.8	843	0	843	13.0
18	2018	64.4	807	0	807	12.5
19	2019	63.3	769	0	769	12.2
20	2020	61.5	730	0	730	11.9
21	2021	59.9	692	0	692	11.6
22	2022	58.4	658	0	658	11.3
23	2023	58.3	635	0	635	10.9
24	2024	57.6	616	0	616	10.7
25	2025	57.6	599	0	599	10.4
2001$						
Net Present Value			11,211	0	11,211	
Nominal Levelized Cost ($/MWh)						17.0
Real Levelized Cost ($/MWh)						13.3

Year	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
2001	0	0	0	0	0	0	#DIV/0!
2002	0	0	0	116	0	116	1.8
2003	0	0	0	112	0	112	1.6
2004	0	0	0	108	0	108	1.6
2005	0	0	0	104	0	104	1.7
2006	0	0	0	100	0	100	1.8
2007	0	0	0	96	0	96	1.9
2008	0	0	0	92	0	92	1.4
2009	0	0	0	88	0	88	1.3
2010	0	0	0	84	0	84	1.2
2011	0	0	0	80	0	80	1.2
2012	0	0	0	76	0	76	1.1
2013	0	0	0	72	0	72	1.1
2014	0	0	0	68	0	68	1.0
2015	0	0	0	64	0	64	1.0
2016	0	0	0	60	0	60	0.9
2017	0	0	0	56	0	56	0.9
2018	0	0	0	52	0	52	0.8
2019	0	0	0	48	0	48	0.8
2020	0	0	0	44	0	44	0.7
2021	0	0	0	40	0	40	0.7
2022	0	0	0	36	0	36	0.6
2023	0	0	0	32	0	32	0.5
2024	0	0	0	28	0	28	0.5
2025	0	0	0	24	0	24	0.4
Net Present Value	0	0	0	832	0	832	
Nominal Levelized Cost ($/MWh)							1.3
Real Levelized Cost ($/MWh)							1.0

Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)
2001	0	0	#DIV/0!	0	0	#DIV/0!
2002	1,622	1,622	25.6	6,470	4,848	76.6
2003	1,562	1,562	22.9	3,678	2,116	31.0
2004	1,502	1,502	22.5	2,513	1,011	15.2
2005	1,438	1,438	23.2	1,868	430	6.9
2006	1,375	1,375	25.1	1,253	(122)	(2.2)
2007	1,317	1,317	26.4	955	(362)	(7.2)
2008	1,262	1,262	18.9	1,600	338	5.1
2009	1,220	1,220	18.3	1,631	411	6.1
2010	1,181	1,181	17.5	1,689	508	7.5
2011	1,140	1,140	16.9	1,700	559	8.3
2012	1,100	1,100	16.4	1,894	794	11.8
2013	1,059	1,059	15.9	1,671	612	9.2
2014	1,019	1,019	15.4	1,695	676	10.2
2015	980	980	14.8	1,671	692	10.5
2016	940	940	14.3	1,655	715	10.9
2017	899	899	13.9	1,638	739	11.4
2018	859	859	13.3	1,639	781	12.1
2019	817	817	12.9	1,602	785	12.4
2020	774	774	12.6	1,881	1,107	18.0
2021	732	732	12.2	1,851	1,119	18.7
2022	694	694	11.9	1,822	1,129	19.3
2023	667	667	11.4	1,796	1,129	19.4
2024	644	644	11.2	1,803	1,159	20.1
2025	623	623	10.8	1,768	1,145	19.9
Net Present Value	12,042	12,042		22,843	10,801	
Nominal Levelized Cost ($/MWh)			18.3			16.1
Real Levelized Cost ($/MWh)			14.3			12.6

Year	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
2001	0	0	0	#DIV/0!	0	#DIV/0!
2002	3,055	130	3,185	50.3	4,807	76.0
2003	2,783	144	2,927	42.9	4,489	65.7
2004	2,652	144	2,796	41.9	4,299	64.4
2005	2,393	138	2,531	40.8	3,969	63.9
2006	2,114	124	2,239	40.9	3,613	66.1
2007	1,920	116	2,037	40.8	3,354	67.2
2008	1,699	160	1,859	27.9	3,121	46.8
2009	1,764	164	1,928	28.9	3,148	47.1
2010	1,846	170	2,015	29.9	3,196	47.4
2011	1,920	174	2,095	31.1	3,235	48.0
2012	1,993	178	2,171	32.3	3,271	48.7
2013	2,049	181	2,230	33.6	3,289	49.5
2014	2,135	186	2,320	35.0	3,339	50.3
2015	2,228	189	2,417	36.6	3,397	51.4
2016	2,319	193	2,512	38.2	3,452	52.4
2017	2,384	196	2,580	39.6	3,479	53.7
2018	2,457	199	2,657	41.3	3,515	54.6
2019	2,500	201	2,701	42.7	3,518	55.6
2020	2,528	200	2,728	44.4	3,502	57.0
2021	2,565	200	2,765	46.2	3,497	58.4
2022	2,603	200	2,803	48.0	3,497	59.9
2023	2,708	205	2,913	49.9	3,580	61.4
2024	2,790	208	2,998	52.1	3,642	63.3
2025	2,909	213	3,122	54.3	3,745	65.1
Net Present Value	23,170	1,615	24,785		36,828	
Nominal Levelized Cost ($/MWh)				37.7		56.0
Real Levelized Cost ($/MWh)				29.5		43.9

Kettle Falls Upgrade

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	6,500	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00
Project Capacity	6.6	MW	Fixed O&M	0.00	2003$ per kW-month		
Heat Rate	12,080	Btu/kWh	Escalation Rates			Insurance Cost	0.0
Peak Gas Useage	1,904	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00
			Variable O&M	2.5	percent	Electric Wheeling	0
			Transportation	2.0	percent	General Inflation	2.5

Variable O&M	2.00	2001$/MWh	
Insurance Cost	0.0	0.3% of installed cost ($000s)	Nominal Discount Rate 7.8 percent
Gas Transport	0.00	2000 $/dth	Real Discount Rate 5.1 percent
Electric Wheeling	0	$/MW-month thru 2006	
General Inflation	2.5	percent	
Electric Wheeling Losses	1.9	percent	

Fixed Costs

Year		Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
2	2002	47.8	1,193	0	1,193	24.9	0	0	0	89	0	89	1.9
3	2003	50.1	1,142	0	1,142	22.8	0	0	0	86	0	86	1.7
4	2004	44.5	1,086	0	1,086	24.4	0	0	0	82	0	82	1.9
5	2005	35.4	1,022	0	1,022	28.9	0	0	0	79	0	79	2.2
6	2006	21.1	949	0	949	45.1	0	0	0	76	0	76	3.6
7	2007	12.6	893	0	893	70.9	0	0	0	73	0	73	5.8
8	2008	22.6	866	0	866	38.4	0	0	0	70	0	70	3.1
9	2009	22.1	836	0	836	37.7	0	0	0	67	0	67	3.0
10	2010	23.7	809	0	809	34.2	0	0	0	64	0	64	2.7
11	2011	23.1	779	0	779	33.8	0	0	0	61	0	61	2.6
12	2012	23.2	751	0	751	32.3	0	0	0	58	0	58	2.5
13	2013	22.3	720	0	720	32.2	0	0	0	55	0	55	2.5
14	2014	21.2	689	0	689	32.6	0	0	0	52	0	52	2.5
15	2015	20.8	660	0	660	31.7	0	0	0	49	0	49	2.3
16	2016	20.7	631	0	631	30.4	0	0	0	46	0	46	2.2
17	2017	20.7	602	0	602	29.1	0	0	0	43	0	43	2.1
18	2018	20.0	572	0	572	28.5	0	0	0	40	0	40	2.0
19	2019	19.7	543	0	543	27.5	0	0	0	37	0	37	1.9
20	2020	20.6	516	0	516	25.1	0	0	0	34	0	34	1.6
21	2021	19.8	484	0	484	24.7	0	0	0	31	0	31	1.6
22	2022	18.6	455	0	455	24.5	0	0	0	27	0	27	1.5
23	2023	18.0	434	0	434	24.2	0	0	0	24	0	24	1.4
24	2024	16.6	414	0	414	25.0	0	0	0	21	0	21	1.3
25	2025	16.1	397	0	397	24.6	0	0	0	18	0	18	1.1
2001$													
Net Present Value			8,394	0	8,394		0	0	0	636	0	636	
Nominal Levelized Cost ($/MWh)						33.2							2.5
Real Levelized Cost ($/MWh)						26.0							2.0

Year		Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
1	2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2	2002	1,281	1,281	26.8	4,038	2,757	57.6	3,192	98	3,290	68.8	4,572	95.6
3	2003	1,227	1,227	24.5	2,194	967	19.3	2,822	105	2,927	58.5	4,155	83.0
4	2004	1,168	1,168	26.3	1,255	87	1.9	2,448	96	2,545	57.2	3,713	83.5
5	2005	1,101	1,101	31.1	872	(229)	(6.5)	1,886	78	1,964	55.5	3,066	86.6
6	2006	1,025	1,025	48.7	533	(492)	(23.4)	1,121	48	1,169	55.5	2,194	104.2
7	2007	966	966	76.7	416	(550)	(43.7)	671	29	701	55.6	1,667	132.3
8	2008	937	937	41.5	853	(83)	(3.7)	772	54	826	36.6	1,763	78.1
9	2009	903	903	40.8	862	(41)	(1.8)	786	54	840	38.0	1,743	78.7
10	2010	874	874	36.9	888	14	0.6	871	60	931	39.3	1,804	76.2
11	2011	840	840	36.4	880	39	1.7	882	60	941	40.8	1,782	77.3
12	2012	809	809	34.8	1,013	204	8.8	923	62	984	42.4	1,793	77.3
13	2013	775	775	34.7	838	63	2.8	925	61	986	44.2	1,761	78.9
14	2014	741	741	35.0	845	104	4.9	918	59	977	46.2	1,718	81.2
15	2015	709	709	34.0	820	111	5.3	947	60	1,007	48.3	1,715	82.4
16	2016	677	677	32.7	795	118	5.7	985	61	1,046	50.5	1,723	83.1
17	2017	645	645	31.2	781	136	6.6	1,025	62	1,087	52.5	1,732	83.7
18	2018	612	612	30.6	775	163	8.1	1,031	62	1,093	54.6	1,705	85.1
19	2019	579	579	29.4	734	155	7.9	1,053	63	1,116	56.6	1,695	85.9
20	2020	549	549	26.7	920	371	18.1	1,125	67	1,192	58.0	1,741	84.7
21	2021	515	515	26.2	901	386	19.7	1,111	66	1,177	59.9	1,692	86.1
22	2022	483	483	26.0	884	401	21.6	1,083	64	1,147	61.8	1,630	87.8
23	2023	459	459	25.5	862	403	22.4	1,089	63	1,153	64.1	1,611	89.6
24	2024	435	435	26.3	859	424	25.6	1,039	60	1,098	66.3	1,534	92.6
25	2025	415	415	25.7	840	425	26.4	1,051	60	1,110	68.9	1,525	94.6
2001$													
Net Present Value		9,030	9,030		12,181	3,151		14,537	680	15,217		24,247	
Nominal Levelized Cost ($/MWh)				35.7			12.5				60.1		95.8
Real Levelized Cost ($/MWh)				28.0			9.8				47.1		75.1

AVISTA Corp.

Interoffice Memorandum
Resource Optimization

DATE: September 12, 2001

TO: Ed Groce

FROM: Clint Kalich CK

SUBJECT: Re-visit of Kettle Falls CT

Per your request, following are revised economic analyses on the Kettle Falls CT. It is important here to recognize the work of Steve Silkworth, as he provided the initial economic models used. Without his efforts, I would expect this memo to take a number of additional days to generate.

Project completion, according to Tomas Dempsey, will cost $1.7 million. Although an exact figure of expenses to date was not provided, you likely recall an initial estimate of $8.5 million for the entire project. Given this assumption, just under $7 million already has been spent ~~to date~~ or committed to be spent on the project.

To evaluate the CT project, two scenarios were performed: 1) combined-cycle operation with the existing Kettle Falls boiler and 2) simple-cycle operation. The attached spreadsheets explain that operating in simple-cycle the new CT would generate losses of approximately $250,000 on expenses of $400,000, per year. The project would generate losses through 2013 and thereafter add positive margins to the Company. Over the 24-year analysis, the net present value of the investment is a loss of $856,000 (2001$). On a per-unit basis, the nominal levelized loss is $6.3 per MWh (2001$).

In combined-cycle, the new CT project generates a positive net present value of nearly $4 million (2001$) over 24 years, or $6.7 per MWh nominal levelized. However, the project does not provide positive cash flow until 2008, losing in the earlier years on average about $90,000 on project costs of $1.0 million annually. Additionally, analyzing the CT as a combined-cycle unit presents a very optimistic picture. Given the plant's heat rate, it is likely that at most times it will not be the least-cost option to run the turbine to add heat to the Kettle Falls boiler. With gas at more than $3 per decatherm, the plant's nearly 9,000 combined-cycle heat rate puts generation at over $25 per MWh.

If you need some additional information or analysis, please give me a call.

attachments

Cc: Lloyd Meyers, Steve Wenke, Steve Silkworth

KF CT Study 09/11/01

These values were given to me from Thomas Dempsey on 9/11/01 for the Kettle Falls CT. This option burns natural gas in simple cycle
and diverts waste heat in a feedwater heater in the existing Kettle Falls boiler for heat recovery.

Heat Rate = 8845 kW/Btu (Higher Heating Value)
Capacity = 7072 kW (SCCT) + 3030 kW (Heat Recovery) = 10,102 kW
Capital required to complete the project = $1,700,000

Kettle Falls SCCT -- Heat Recovery in Kettle Falls Boiler

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	1,700	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00	2001$/MWh	Electric Wheeling Losses	1.9 percent
Project Capacity	10.1	MW	Fixed O&M	0.00	2003$ per kW-month					
Heat Rate	8,846	Btu/kWh	Escalation Rates			Insurance Cost	0.8	0.3% of installed cost ($000s)	Nominal Discount Rate	7.8 percent
Peak Gas Useage	2,144	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00	2000 $/dth	Real Discount Rate	5.1 percent
			Variable O&M	2.5	percent	Electric Wheeling	0	$/MW-month thru 2006		
			Transportation	2.8	percent	General Inflation	2.5	percent		

Profitability Index: 2.31596

Fixed Costs

	Year	Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
2	2002	22.3	306	0	306	13.7	0	0	0	23	0	23	1.0
3	2003	19.4	293	0	293	15.1	0	0	0	22	0	22	1.2
4	2004	23.4	290	0	290	12.4	0	0	0	22	0	22	0.9
5	2005	30.2	290	0	290	9.6	0	0	0	21	0	21	0.7
6	2006	23.1	269	0	269	11.7	0	0	0	20	0	20	0.9
7	2007	30.2	271	0	271	9.0	0	0	0	19	0	19	0.6
8	2008	40.2	276	0	276	6.9	0	0	0	18	0	18	0.5
9	2009	45.0	273	0	273	6.1	0	0	0	18	0	18	0.4
10	2010	45.0	267	0	267	5.9	0	0	0	17	0	17	0.4
11	2011	45.0	262	0	262	5.8	0	0	0	16	0	16	0.4
12	2012	45.3	257	0	257	5.7	0	0	0	15	0	15	0.3
13	2013	45.0	251	0	251	5.6	0	0	0	14	0	14	0.3
14	2014	81.1	313	0	313	3.9	0	0	0	14	0	14	0.2
15	2015	80.9	311	0	311	3.8	0	0	0	13	0	13	0.2
16	2016	81.2	309	0	309	3.8	0	0	0	12	0	12	0.1
17	2017	77.9	300	0	300	3.8	0	0	0	11	0	11	0.1
18	2018	78.1	297	0	297	3.8	0	0	0	10	0	10	0.1
19	2019	75.2	288	0	288	3.8	0	0	0	10	0	10	0.1
20	2020	75.2	284	0	284	3.8	0	0	0	9	0	9	0.1
21	2021	74.9	279	0	279	3.7	0	0	0	8	0	8	0.1
22	2022	74.9	276	0	276	3.7	0	0	0	7	0	7	0.1
23	2023	77.9	281	0	281	3.6	0	0	0	6	0	6	0.1
24	2024	78.3	282	0	282	3.6	0	0	0	6	0	6	0.1
25	2025	78.1	281	0	281	3.6	0	0	0	5	0	5	0.1
2001$													
Net Present Value			2,826	0	2,826		0	0	0	166	0	166	
Nominal Levelized Cost ($/MWh)						4.8							0.3
Real Levelized Cost ($/MWh)						3.8							0.2

Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2002	329	329	14.7	246	(83)	(3.7)	681	45	726	32.5	1,055	47.2
2003	316	316	16.2	200	(116)	(6.0)	613	39	652	33.6	967	49.8
2004	311	311	13.3	208	(103)	(4.4)	742	47	789	33.7	1,101	47.0
2005	311	311	10.3	244	(67)	(2.2)	937	60	997	33.1	1,308	43.4
2006	289	289	12.5	202	(87)	(3.8)	701	46	747	32.3	1,036	44.9
2007	290	290	9.6	277	(13)	(0.4)	902	60	962	31.9	1,252	41.5
2008	295	295	7.3	359	64	1.6	1,171	80	1,251	31.2	1,546	38.5
2009	291	291	6.5	467	176	3.9	1,269	90	1,359	30.2	1,650	36.7
2010	284	284	6.3	494	210	4.7	1,313	90	1,403	31.2	1,687	37.5
2011	278	278	6.2	502	224	5.0	1,363	90	1,453	32.3	1,730	38.5
2012	272	272	6.0	507	235	5.2	1,426	91	1,516	33.5	1,788	39.5
2013	265	265	5.9	514	249	5.5	1,472	90	1,562	34.7	1,827	40.6
2014	326	326	4.0	1,522	1,196	14.7	2,857	162	3,019	37.2	3,346	41.3
2015	323	323	4.0	1,488	1,165	14.4	2,985	162	3,147	38.9	3,470	42.9
2016	321	321	4.0	1,464	1,143	14.1	3,123	162	3,286	40.5	3,607	44.4
2017	311	311	4.0	1,432	1,121	14.4	3,096	156	3,252	41.7	3,563	45.7
2018	308	308	3.9	1,415	1,107	14.2	3,216	156	3,372	43.2	3,680	47.1
2019	298	298	4.0	1,452	1,155	15.4	3,193	150	3,344	44.5	3,641	48.4
2020	293	293	3.9	1,495	1,203	16.0	3,277	150	3,427	45.6	3,720	49.4
2021	287	287	3.8	1,534	1,247	16.7	3,340	150	3,490	46.6	3,777	50.5
2022	283	283	3.8	1,575	1,292	17.3	3,423	150	3,573	47.7	3,856	51.5
2023	288	288	3.7	1,621	1,334	17.1	3,647	156	3,803	48.8	4,091	52.5
2024	288	288	3.7	1,671	1,383	17.7	3,759	157	3,916	50.0	4,203	53.7
2025	286	286	3.7	1,716	1,430	18.3	3,842	156	3,998	51.2	4,284	54.9
Net Present Value	2,993	2,993		8,646	3,937		16,247	905	17,152		20,144	
Nominal Levelized Cost ($/MWh)			5.1			8.7				29.2		34.3
Real Levelized Cost ($/MWh)			4.0			5.3				22.9		26.9

AVISTA UTILITIES

Kettle Falls CT Case II
Simple Cycle CT with HRSG and steam sent to feedwater heater

09-12-2001 Kettle Falls CT Economics 091101--Combined-Cycle.xls agk

Exhibit No._____(RJL-23)

Docket No. UE-01______

Kettle Falls SCCT -- Simple Cycle Only

Avista Corporation

Economic Analysis Detail

Assumptions

Installed Cost	1,700	$000s	Fixed Charge	0.00	per kW-month	Variable O&M	2.00	2001$/MWh
Project Capacity	8.6	MW	Fixed O&M	0.00	2003$ per kW-month			
Heat Rate	12,080	Btu/kWh	Escalation Rates			Insurance Cost	0.0	0.3% of installed cost ($000s)
Peak Gas Useage	1,913	000s dth	Fixed O&M	2.5	percent	Gas Transport	0.00	2000 $/dth
			Variable O&M	2.5	percent	Electric Wheeling	0	$/MW-month thru 2006
			Transportation	2.0	percent	General Inflation	2.5	percent

Electric Wheeling Losses	1.9	percent
Nominal Discount Rate	7.8	percent
Real Discount Rate	5.1	percent
Profitability Index	-0.50380	

Fixed Costs

Year		Energy (GWh)	Capital Recovery and Miscellaneous: Project ($000s)	Fixed Chrg. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)	Operations & Maintenance: Fixed ($000s)	Gtrans ($000s)	Etrans ($000s)	PrTax ($000s)	Insur. ($000s)	Total Costs ($000s)	Total Costs ($/MWh)
1	2001	0.0	0	0	0	#DIV/0!	0	0	0	0	0	0	#DIV/0!
2	2002	2.7	276	0	276	102.0	0	0	0	23	0	23	8.6
3	2003	2.6	267	0	267	102.5	0	0	0	22	0	22	8.6
4	2004	2.6	258	0	258	98.8	0	0	0	22	0	22	8.3
5	2005	2.7	248	0	248	91.7	0	0	0	21	0	21	7.7
6	2006	2.7	239	0	239	88.3	0	0	0	20	0	20	7.4
7	2007	2.7	230	0	230	85.0	0	0	0	19	0	19	7.1
8	2008	7.3	231	0	231	31.7	0	0	0	18	0	18	2.5
9	2009	7.3	221	0	221	30.3	0	0	0	18	0	18	2.4
10	2010	10.0	218	0	218	21.9	0	0	0	17	0	17	1.7
11	2011	7.3	206	0	206	28.3	0	0	0	16	0	16	2.2
12	2012	7.2	198	0	198	27.8	0	0	0	15	0	15	2.1
13	2013	7.2	190	0	190	26.5	0	0	0	14	0	14	2.0
14	2014	22.4	220	0	220	9.9	0	0	0	14	0	14	0.6
15	2015	22.5	215	0	215	9.6	0	0	0	13	0	13	0.6
16	2016	22.5	209	0	209	9.3	0	0	0	12	0	12	0.5
17	2017	22.4	203	0	203	9.1	0	0	0	11	0	11	0.5
18	2018	19.8	190	0	190	9.6	0	0	0	10	0	10	0.5
19	2019	19.8	184	0	184	9.3	0	0	0	10	0	10	0.5
20	2020	19.9	177	0	177	8.9	0	0	0	9	0	9	0.4
21	2021	19.9	171	0	171	8.6	0	0	0	8	0	8	0.4
22	2022	19.9	165	0	165	8.3	0	0	0	7	0	7	0.4
23	2023	19.8	161	0	161	8.1	0	0	0	6	0	6	0.3
24	2024	19.8	157	0	157	8.0	0	0	0	6	0	6	0.3
25	2025	19.9	155	0	155	7.8	0	0	0	5	0	5	0.2
2001$													
Net Present Value			2,235	0	2,235		0	0	0	166	0	166	
Nominal Levelized Cost ($/MWh)						16.5							1.2
Real Levelized Cost ($/MWh)						13.0							1.0

Year	Total Fixed Costs: Before 10% Credit ($000s)	After 10% Credit ($000s)	After 10% Credit ($/MWh)	Less Operating Margin ($000s)	Net Project Benefit ($000s)	Net Project Benefit ($/MWh)	Variable Costs: Gas ($000s)	O&M ($000s)	Total Variable ($000s)	Total Variable ($/MWh)	Total Project Cost after Credits ($000s)	Total Project Cost after Credits ($/MWh)
2001	0	0	#DIV/0!	0	0	#DIV/0!	0	0	0	#DIV/0!	0	#DIV/0!
2002	299	299	110.6	28	(271)	(100.2)	110	5	116	42.7	415	153.2
2003	290	290	111.1	21	(268)	(102.9)	109	5	114	43.7	404	154.8
2004	279	279	107.0	20	(259)	(99.3)	110	5	115	44.3	395	151.3
2005	269	269	99.3	24	(245)	(90.6)	112	5	118	43.5	387	142.8
2006	259	259	95.6	20	(239)	(88.2)	110	5	116	42.7	375	138.3
2007	249	249	92.1	28	(222)	(81.9)	108	5	113	41.9	363	133.9
2008	249	249	34.2	48	(201)	(27.6)	285	15	300	41.2	548	75.4
2009	238	238	32.8	98	(140)	(19.2)	248	15	263	36.2	501	68.9
2010	236	236	23.6	110	(125)	(12.6)	366	20	386	38.6	621	62.2
2011	221	221	30.5	107	(115)	(15.8)	267	15	282	38.7	503	69.2
2012	213	213	29.7	107	(106)	(14.8)	274	14	288	40.2	501	69.9
2013	206	206	28.5	108	(97)	(13.5)	284	14	299	41.7	503	70.2
2014	234	234	10.5	477	243	10.9	1,052	45	1,097	49.0	1,331	59.5
2015	228	228	10.1	450	222	9.9	1,106	45	1,151	51.2	1,379	61.3
2016	221	221	9.9	424	202	9.0	1,154	45	1,199	53.4	1,421	63.2
2017	215	215	9.6	402	188	8.4	1,197	45	1,242	55.5	1,456	65.1
2018	201	201	10.2	389	188	9.5	1,099	40	1,139	57.6	1,340	67.8
2019	193	193	9.8	401	208	10.5	1,127	40	1,166	59.0	1,360	68.8
2020	186	186	9.4	412	226	11.4	1,161	40	1,201	60.4	1,387	69.8
2021	179	179	9.0	423	244	12.3	1,191	40	1,230	61.9	1,409	70.9
2022	172	172	8.7	434	262	13.2	1,220	40	1,260	63.4	1,432	72.1
2023	167	167	8.5	446	279	14.1	1,243	40	1,283	64.9	1,450	73.4
2024	163	163	8.3	459	296	15.0	1,275	40	1,315	66.5	1,478	74.8
2025	159	159	8.0	472	312	15.7	1,314	40	1,353	68.1	1,513	76.2
Net Present Value	2,401	2,401		1,606	(856)		4,618	186	4,804		7,205	
Nominal Levelized Cost ($/MWh)			17.8			(6.3)				35.5		53.3
Real Levelized Cost ($/MWh)			13.8			(5.0)				27.8		41.8

BEFORE THE

WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

DOCKET NO. UE-01_____

EXHIBIT NO. __ (RJL-25)

Coyote Springs II - O&M Costs

	Total	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
Shared Fixed Costs	$815,509	$66,517.86	$66,517.86	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32	$68,247.32
Unit Specific Fixed Costs	$139,589	$11,385.71	$11,385.71	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74	$11,681.74
Port of Morrow Fees	$299,500	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33	$24,958.33
Major Maint. - Fixed Costs	$375,000	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00	$31,250.00
Sub-Total - Fixed Costs	$1,629,598												
Shared Variable Costs	$60,590	$4,942.09	$4,942.09	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58	$5,070.58
Unit Specific Variable Costs	$110,136	$8,983.40	$8,983.40	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97	$9,216.97
Major Maint. - Variable Costs	$1,027,808	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69	$85,650.69
Sub-Total Variable Costs	$1,198,535	$1.56 /MWh											
Total	$2,828,133												

Note: 1) Based on 5971 hours of operation. (776,131MWh/128.3MW=5971hrs)
2) 2003 PGE Operations Costs escallated at 2.6 %
3) Nov 2002 through Oct 2003 period

11-27-2001

Exhibit No.____(RJL-25)
Docket No. UE-01____
Page 1 of 2

Boulder Park

Item	Total	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
Manpower													
Journeyman Plant Specialist	$ 79,249.01	$ 6,464.03	$ 6,464.03	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09	$ 6,632.09
Journeyman Plant Specialist OT	$ 13,089.38	$ 1,526.31	$ 1,526.31	$ 1,662.21	$ 810.84	$ 1,621.66	$ 810.84	$ 1,216.25	$ 782.99	$ 782.99	$ 782.99	$ 782.99	$ 782.99
Wartsila Contract?	$ -												
Transportation													
Pick-Up Truck	$ 11,034.00	$ 900.00	$ 900.00	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40	$ 923.40
Gas	$ 1,226.00	$ 100.00	$ 100.00	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60
Training													
Class/User Group	$ 8,208.00					$ 4,104.00			$ 4,104.00				
Operating													
Lube Oil	$ 18,981.00			$ 3,591.00							$ 5,130.00	$ 5,130.00	$ 5,130.00
Miscellaneous	$ 9,808.00	$ 800.00	$ 800.00	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80	$ 820.80
Light Bulbs													
Toilet Paper													
Rags/Linens													
Phone													
Office Supplies													
Computer Refresh													
Sewer													
Garbage/Waste													
Etc													
Anti-Freeze	$ 5,504.49			$ 1,041.39							$ 1,487.70	$ 1,487.70	$ 1,487.70
Hazardous Waste Disposal	$ 12,260.00	$ 1,000.00	$ 1,000.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00
Lube Oil													
Anti-Freeze													
Etc													
Urea	$ 22,777.20			$ 4,309.20							$ 6,156.00	$ 6,156.00	$ 6,156.00
Spark Plugs	$ 9,110.88			$ 1,723.68							$ 2,462.40	$ 2,462.40	$ 2,462.40
Spark Plug Wires	$ 3,796.20			$ 718.20							$ 1,026.00	$ 1,026.00	$ 1,026.00
Spare Parts	$ 12,260.00	$ 1,000.00	$ 1,000.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00
Domestic Water	$ 1,226.00	$ 100.00	$ 100.00	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60	$ 102.60
Weed Control	$ 4,104.00						$ 2,052.00			$ 2,052.00			
Landscaping	$ 5,130.00						$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00		
Sprinkler System	$ 5,130.00						$ 5,130.00						
Communications (T1 line)	$ 7,969.00	$ 650.00	$ 650.00	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90	$ 666.90
Tools	$ 12,260.00	$ 1,000.00	$ 1,000.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00
Misc. Parts, etc.	$ 12,260.00	$ 1,000.00	$ 1,000.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00	$ 1,026.00
Computer													
Maintenance													
Misc. Maintenance - Fixed	$ 101,300.00		$ 25,000.00			$ 25,000.00			$ 25,650.00			$ 25,650.00	
Environmental													
Urea/Ammonia (See above)													
Total	$ 356,683.16												

Note: 1) Based on 2700 hours of operation.
2) 2003 Costs escallated at 2.6%

11-27-2001