Before the
STATE OF OREGON
ENERGY FACILITY SITING COUNCIL

	)	
In the matter of the 500	)	
Megawatt Exemption from the	)	
Demonstration of Showing Need	)	**ORDER**
for a Power Plant	)	
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I. INTRODUCTION

This Order is issued following the conclusion of a contested case proceeding pursuant to the procedures and criteria of OAR 345-23-0010(2) The purpose of this Order and the underlying proceeding is to award a single 500 Megawatt (MW) exemption from the demonstration of need for a power plant under ORS 469.501(1)(L). This exemption was created by the 1995 session of the Legislative Assembly and is codified in ORS 469.501(2). Through rulemaking, the Council developed a format and procedure to award the exemption to the proposed facility with the least environmental impact as defined in OAR 345-23-0010(2) ("the exemption rule").

In the exemption rule, the Council developed a four part test for determining which plant had the least environmental impact. At each level where a tie exists among two or more prevailing applicants, the Council moves the inquiry to the next part of the test for the prevailing applicants. Under the first part, the Council awards the exemption to the applicant with the "lowest value for monetized net air emissions." The second part of the test considers each proposal's impact on water. The third part of the test weighs the land use impacts of each proposal's related or supporting facilities. Finally, the Council awards the exemption to the applicant with the oldest application determined complete by the Department.

The Council in this Order concludes that one applicant, Klamath Cogeneration Project (KG), prevails under the first part of the test specified in the exemption rule test. The Council, nonetheless, proceeds to analyze each proposal under each part of the test in this Order. It is the intent of the Council that this Order be considered a Final Order, subject to judicial review.

II. PROCEDURAL BACKGROUND

On February 13, 1996, the Office of Energy (OE) initiated this proceeding by issuing a Notice of Contested Case Proceeding. The

Notice of Contested Case Proceeding set several deadlines: (1) directing site certificate applicants to file requests for the exemption by March 1, 1996; (2) granting private parties until March 5 to file requests to participate; (3) requiring objections to requests to participate to be filed by March 8; and (4) setting an initial prehearing conference for March 11. The Notice also designated Jeffrey P. Chicoine as the hearing officer responsible for conducting the contested case proceeding and issuing a proposed order.

By the filing deadline, requests for exemptions were received from Hermiston Power Partnership (HPP), Umatilla Generating Company (UGC) and the Klamath Cogeneration Project (KG). Timely requests to participate were also filed by several private parties, including Northwest Environmental Advocates (NEA), Allen Lambert and Pacific Gas Transmission Company. On March 6, 1996, requests to participate were filed by the Don't Waste Oregon Council (DWOC), the Northwest Environment and Self-Reliance Trust (NEST), Lloyd Marbet, Colleen O'Neil and the Utility Reform Project (URP). HPP filed objections to the March 6 requests to participate.

On March 6, the hearing officer issued an initial prehearing order outlining a schedule for the contested case proceeding, setting the agenda for the initial prehearing conference and authorizing OE to submit data requests to applicants on March 8.

On March 11, the initial prehearing conference was held as set in the Notice of Contested Case Proceeding. The hearing officer granted the requests to participate of all parties, except one. The hearing officer denied the request of NEST on the grounds that there was no showing that other parties could not adequately represent the interests in this proceedings that NEST had identified. See OAR 137-03-005(3)(f). Schedules and procedures were discussed at length among the hearing officer and the parties' representatives.

Rulings regarding schedules and procedures were recorded in the Prehearing Conference Order issued on March 13, 1996. In the Prehearing Conference Order, the hearing officer directed that responses to data requests, document requests or interrogatories were not to be filed with the hearing officer. These documents were not considered part of the evidentiary record of the case, unless specifically offered and received into evidence at the hearing.

On March 14, 1996, the hearing officer issued an Order regarding Confidential Information and Protective Order. This Order provided a framework for the limited disclosure of confidential information to parties stipulating to the terms of the Order.

On March 22, 1996, the hearing officer issued a Notice of Contested Case Rights and Procedures as required by ORS 183.413(2). The burden of going forward and burden of proof was placed on each party to show that their proposal best satisfied the criteria of OAR 345-23-0010(2).

KG's Motion for Partial Dismissal of HPP's Mitigation Fund

On March 15, 1996, KG filed a Motion for Partial Dismissal of the Mitigation Fund from HPP's Request for Exemption with accompanying memorandum. On March 25, the hearing officer issued an Order denying the motion. The hearing officer agreed with KG that an offset, which was deficient as a matter of law, should not be considered and could be stricken, dismissed or otherwise removed from consideration at an early date in these proceedings as a matter of administrative economy. The hearing officer, however, after reviewing ORS chapter 469, the rules, and the parties' arguments ruled that he could not make the determination that HPP's mitigation fund is legally deficient. The hearing officer found that nothing precluded a mitigation fund approach. The hearing officer ruled that any mitigation fund, including HPP's mitigation fund, must be reviewed as to its uncertainty, quantifiability and verifiability under OAR 345-23-0010(2)(b) & (c) through the testimonial portion of this proceeding. As discussed below, we disagree with the hearing officer's apparent conclusion that the fund is a "measure".

HPP's Motion to Exclude KG's Amendment to its Application

On March 18, 1996, HPP filed a Motion to Exclude Amendment to Application on the grounds that the cogeneration contract should have been, but was not, enclosed with KG's "Application for Exemption," referred to as a Request. On March 25, 1996, the hearing officer issued an order denying HPP's motion, noting that KG had not sought to amend its application. The hearing officer rejected HPP's argument that the post-application production of the memorandum of understanding between KG and its cogeneration host, Weyerhaeuser Company, was tantamount to an amendment of its application. The word "demonstrated" in OAR 345-23-0010(2)(a)-(c) did not require that the contract be submitted with the Application. Cogeneration, to be considered an offset, need only be the subject of a contractual agreement. The hearing officer ruled that the Request sufficiently established or "demonstrated" that cogeneration was subject to a contractual agreement by describing the arrangement with the cogeneration host.

KG's Redaction of the Cogeneration Memorandum

On March 21, 1996, KG filed an application seeking additional protection of confidential information. Specifically, KG asked that it be permitted to redact, without disclosing, terms of its memorandum of understanding with Weyerhaeuser regarding steam cogeneration. Specifically, KG redacted terms relating to the sales price of steam and conditions placed on land to be leased from Weyerhaeuser for the plant. No parties opposed the motion, and both HPP and OE filed statements that they were not challenging the redaction as proposed by KG. By Order dated April 1, 1996, the hearing officer granted KG's motion.

In OE's March 27, 1996 response to Klamath' Motion for Additional Protection, OE challenged Klamath's claim that unredacted portions of the Weyerhaeuser agreement were confidential. OE's challenge was made pursuant to paragraph 15 b. of the Order regarding Confidential Information and Protective Order. In response, KG withdrew its claim of confidentiality for the unredacted portions of the Weyerhaeuser agreement. As a result, no order was issued.

KG's Amendment of the Application

By letter dated March 27, 1996, KG submitted its Memorandum of Understanding with Weyerhaeuser as a late-filed portion its application. On March 27, the hearing officer issued a "Notice of Scheduling" stating that he was considering that KG's request was a motion to amend the application and would reserve ruling on the motion to permit parties an opportunity to file argument regarding the motion.

On April 3, the hearing officer denied KG's request to submit its redacted contract as part of its application. The hearing officer viewed the request as an amendment to the application and found that the Council, in its rulemaking, expressly rejected the option of permitting applicants the opportunity to amend their applications. The hearing officer noted that nothing barred Klamath from offering the contract document into the record during evidentiary proceedings as an exhibit.

We discuss this issue in more detail below.

Motions for Additional Time to File Direct Testimony

As set in the Prehearing Conference Order, the initial written direct testimony for all parties was due April 2. DWOC and OE filed requests for additional time to file initial direct testimony. Other parties either agreed or had no objection to their motions. By order dated April 1, the hearing officer reset the due date for the first round of prefiled direct testimony for all parties to April 4, 1996, reset the cutoff date for the filing of follow-up interrogatories to April 8, 1996, and set a scheduling conference for April 10.

On April 10, a scheduling conference was held. At the conference, the hearing officer decided to maintain the setting of the cross-examination hearing for April 22 through April 26. The hearing officer also decided to trifurcate the hearing addressing the power plant and cogeneration facilities on Monday and Tuesday, April 22 and 23, addressing the offsets on Wednesday and Thursday, April 24 and 25 and addressing the water quality and land use issues on Friday, April 26. These rulings were recorded in an Order issued April 15, 1996. The April 15 Order also set the order for the parties to present evidence and cross-examine witnesses.

The Hearing

A hearing was held as scheduled from April 22 through April 26. With agreement of the parties, the hearing officer split the water quality and land use portions of the hearing apart so that the hearing was held in four separate parts. No limitation was placed on the use of testimony from one part of the hearing in addressing issues raised in another part of the hearing.

The hearing was attended at all times by representatives of each applicant, OE and Northwest Environmental Advocates. Intervenors DWOC and Colleen O'Neil were represented during a portion of the first part of the hearing on power plant and cogeneration facilities. All parties had opportunity to present direct examination, cross-examine the witnesses of other parties and present documentary evidence.

During the hearing, the hearing officer made it clear that only information received into evidence and made part of the evidentiary record would be considered in issuing this Order. With agreement of the parties present, the hearing officer ruled that the applicant's request for exemption and application for site certificates constituted part of the evidentiary record. Also, during the hearing, the parties moved for admission of their witnesses' prefiled initial and rebuttal direct written examination following sworn authentication by the witness. The hearing officer received into evidence prefiled testimony with attached exhibits, as noted on the hearing transcript. Additional documentary evidence was offered and received into evidence. Responses to document requests were not considered part of the record, unless specifically offered into evidence.

At the conclusion of the hearing on Friday, April 26, the hearing officer closed the evidentiary record and adjourned the hearing. In closing the record, the hearing officer stated that he would not reopen the record for additional evidence. The hearing officer also stated that he would take official notice of any Council order or site certificate, the Council rulemaking record for the exemption rule and any order of the Public Utility Commission.

A court reporter transcribed the entire cross-examination hearing and prepared five volumes of transcripts. These transcripts are part of the official record of these proceedings.

Each of the applicants, NEA and OE submitted posthearing filings. KG filed a brief and proposed findings facts and conclusions of law. UGC filed proposed findings of facts and proposed order. OE filed a brief and proposed findings of facts and proposed order. NEA filed a brief. Each was duly considered by the hearing officer.

Posthearing Motions of Utility Reform Project and Office of Energy

After the close of the evidentiary record, the Utility Reform Project requested that the hearing officer receive into evidence pre-filed testimony of Dan Meek. In addition, the Office of Energy requested that the hearing officer receive into evidence both spreadsheets it had prepared based on testimony at the hearing and responses to data requests that had been shared among the parties.

The hearing officer admitted the responses to data requests offered by OE, but rejected the spreadsheets and Mr. Meek's testimony. Both OE and Mr. Meek took exception to the hearing officer's refusal to admit Mr. Meek's testimony.

We agree with the hearing officer that the OE spreadsheets are not factual evidence but are part of OE's argument. They need not be admitted as evidence.

No party objected to admission of Mr. Meek's testimony or the responses to data requests requested by OE. Therefore, we grant the Utility Reform Project motion and OE's motion with respect to the data responses.

Issuance of Proposed Order

The hearing officer issued a proposed order on June 7, 1996. All three applicants, the Office of Energy and the Utility Reform Project filed exceptions on June 18, 1996. The Council heard argument on these exceptions at its meeting on June 27 and 28, 1996. The Council has considered the exceptions and incorporates its resolution of the issues raised by the parties in this order.

Council Review of the Hearing Officer's Procedural Rulings

Except where noted otherwise in this order, the hearing officer's rulings were correct.

III. PRELIMINARY ISSUES

The Council determined that it would use the contested case proceeding under the Administrative Procedure Act (APA) to issue the one-time legislatively created exemption from the need requirement. To govern both procedural and substantive issues in this contested case proceeding, the Council adopted OAR 345-23-010(2) ("the exemption rule"). As a preliminary matter in this proceeding, several issues need to be addressed.

A. Amendments

Applicants submitted formal requests for exemption. Then, through a series of data request responses and through their testimony, applicants have added further detail to or clarified their proposals. Although the exemption rule does not bar an applicant from explaining, justifying or clarifying a proposal as part of the proceeding, it is impermissible for an applicant to attempt to "up its bid" or to lower it once its proposal has been made. Although the text of OAR 345-23-010(2) does not expressly address amendments, all participants were aware that they are not authorized. It is clear from our rules that when we intend to authorize amendments, we have done so explicitly. *See* OAR 345-21-090. In addition, when we adopted this rule, we clearly rejected the option of successive rounds of bidding. (*See e.g.* 500 MW Record, 12-16, 95-97, 158-160, 170.)

We expected applicants to make their best case in their request for exemption, and did not intend to authorize them to "up the ante" after seeing other applicants' proposals. Permitting applicants to change their requests would be in essence allowing additional rounds of bidding.

We also recognize that some type of clarification and gap-filling is necessary in order for the parties and the Council to understand exactly what each applicant proposed in its request for exemption. In exceptions, UGC argued that the hearing officer's conclusions with respect to the amount of distillate fuel that will be burned in the HPP and KG facilities creates impermissible amendments of those requests. (UGC-42.30-.33) As noted below, we are not persuaded by these claims. Despite the applicants' protests, none of the clarifications made during the proceeding constituted amendments.

B. Burden and Standard of Proof

While certain modifications to APA procedures were made in the exemption rule, none addressed the burden or standard of proof required by applicants for the exemption. Consequently, those issues are governed by the APA.

Under ORS 183.450(1), evidence "of a type commonly relied upon by reasonably prudent persons in conduct of their serious affairs shall be admissable." Under ORS 183.450(2), the burden of presenting evidence to support a fact or position rests on the proponent. Thus, each party bears the burden of proving that its application best satisfies the Council's criteria for issuing the exemption.

In addition, as here, where a statute does not impose another standard of proof, the standard of proof is the preponderance of the evidence. *See Oregon State Correctional Institution v. Bureau of Labor and Industries,* 98 Or App 548, 555, 780 P2d 743, *rev den*, 308 Or 660 (1989.)

C. The Role of the Office of Energy

OE's role in this proceeding is not clearly defined in statute or rule. In proceedings governing the application for site certificate (ASC), OE conducts a comprehensive review of the ASC, issuing a project order, issuing a draft proposed order, conducting a public review and issuing a proposed order. See ORS 469.330 & 469.370. Unlike in site certificate proceedings, OE is delegated no decision making authority in this proceeding. The exemption rule merely states that OE "shall be authorized to participate as an interested agency" in this proceeding. OAR 345-23-010(2)(a)(C). OE's role is therefore limited to that of a party, offering testimony as any other party.

Testimony offered by OE's witnesses within their realm of expertise is therefore credited, subject to rebuttal by other expert testimony. Furthermore, when OE promotes a position that issue must be supported by evidence of record under the preponderance of the evidence standard. Unlike the applicants witnesses, however, OE's testimony must be accorded the consideration appropriate to an unbiased observer.

D. Significantly Greater Values

1. Monetized Net Emissions

Under OAR 345-23-010(2)(b), we must award the exemption to the facility with the lowest value for monetized net air emissions unless other proposals "have values for monetized net air emissions per kWh net electric output that are not significantly greater than the proposal with the lowest value for monetized net air emissions * * *." OAR 345-23-010(2)(b)(D).

The term "significant" is defined at OAR 345-01-010(45). It provides:

> "Significant" means having an important consequence, either alone or in combination with other factors, based upon the magnitude and likelihood of the impact on the affected human population or natural resources, or on the importance of the natural resource affected, considering the context of the action or impact, its intensity and the degree to which possible impacts are caused by the proposed action. Nothing in this definition is intended to require a statistical analysis of the magnitude or likelihood of a particular impact.

This definition does not apply in this situation. The term used in OAR 345-23-010(2) is "not significantly greater," while the defined term is "significant." The definition is clearly phrased in terms of magnitude and likelihood of *impacts* from a facility. It makes no sense to evaluate a number that reflects a per kWh comparison of proposals by assessing magnitude and likelihood of impacts. The question "does a some number of mills/kWh have important consequences?" is nonsensical.

By establishing this rule and requiring a comparison of net air emissions normalized in terms of mills/kWh, we have already announced our judgment that impacts from CO_2, NO_x and PM-10 have an important consequence in terms of impacts on affected human populations and natural resources. All the applicants have made substantial proposals to address these concerns. These proposals do differ, and as explained below, we conclude that KG's proposal is significantly superior to the other proposals.

2. Impact to Water and Land

Application of the defined phrase "significantly greater" does not present the same analytical problems with respect to water or land use impacts because those impacts are not evaluated on a per kWh basis. We may employ the defined term "significant" in evaluating water and land use impacts.

IV. NET MONETIZED EMISSIONS -- ISSUES AND ASSUMPTIONS

A. The Governing Rules

Under OAR 345-23-0010(2)(b), the Council must award the exemption to the applicant whose proposal has the "lowest value for monetized net air emissions" based on per kWh of electric output.

1. Gross emissions

In making this determination, the Council must first calculate gross emissions from the generation of electric output and estimate the amount of electric output expected to be generated during the life of the proposed plant pursuant to the following provisions:

> (b) The exemption shall be awarded to the proposal with the lowest value for monetized net air emissions per kWh of net electric output.
>
> (1) Net air emissions shall be the facility's emissions of carbon dioxide (CO_2), oxides of nitrogen (NO_x) and PM-10 particulates (particles less than 10 microns) minus firm offsets of the same pollutants assured in the application. Net air emissions shall be monetized by applying the dollar values in Table 1 of OAR 345-01-010(35), except that NO_x and PM-10 offsets outside Oregon shall be assigned a value of zero dollars per ton.
>
> (2) CO_2 emissions from the facility shall be based on the annual fuel input to the facility times the carbon content of the fuel. Firm offsets from cogeneration shall be based on annual fuel displaced by firm cogeneration times the carbon content of the fuel displaced. * * *

OAR 345-23-0010(2). Air emissions are monetized based on the rate of $10/ton of carbon dioxide (CO_2) emissions and $2000 per ton of emissions of oxides of nitrogen (NOx) or particulates of less than 10 microns (PM-10.) OAR 345-01-010(35).

2. Net emissions

Gross emissions may be offset by emissions "sequestered, avoided or displaced" through either cogeneration or mitigation measures. OAR 345-23-010(2)(b)(C). The provision states:

> "(C) Firm offsets of air emissions shall be based on an estimate of emissions sequestered, avoided or displaced by the applicant's mitigation measures or cogeneration, provided such measures are guaranteed by an assurance bond or performance bond or can be made binding through other site certificate conditions. Firm offsets from cogeneration mean that the cogeneration is achieved by the applicant as part of the facility, demonstrated by a contractual agreement between the applicant and the cogeneration host and made binding through site certificate conditions. In determining the amount of the firm offsets of air emissions, the Council shall consider the timing of the offset, the uncertainty, quantifiability and verifiability of the estimate of the amount of offset and the applicant's proposed measurement, monitoring and evaluation of the performance of the offset."

The applicant with the lowest monetized net air emissions prevails if the next higher applicant's values "are significantly greater" than its value. . If two or more applicants are "tied" in that one is not significantly greater than the lowest they proceed to the next part of the test.

B. Some General Issues Regarding Emissions Calculations

1. Proofs and evidence relied upon in this proceeding

HPP notes that the emission calculations generally rely on the calculation of a single point of expected output without identifying a range of possible outcomes. (HPP-32.33.) HPP contends that not knowing the range makes it impossible to compare the relative value of proposals.

We note first that the emissions calculations actually rely on single points, not necessarily mid-points. Such testimony is admissible in this contested case proceeding because it is precisely the type of information on which reasonably prudent persons routinely rely in their serious affairs. ORS 183.450(1). Moreover, the exemption rule expressly calls for an "estimate" of emissions, which contemplates a single point calculation.

Second, we believe that it is reasonable to rely on the single-point calculation as the likely outcome or result. The range itself only defines the possible outcomes. The Council's responsibility is to determine the likely outcome or result regarding emissions and make a conclusion based on such factual determinations.

While the precise issue posed by HPP is a novel one, Oregon law has ample experience in analyzing prospective value of businesses, property and profits. For example, in *State ex rel United States Financial Systems v. Holst*, 102 Or App 247, 250-51 (1990), the court declined to award damages for loss of goodwill without specific proof showing that actual goodwill was lost and some proof of the amount of loss. The court ruled that there must be "sufficient data from which court or jury may properly estimate the amount of damages, which date shall be established by facts rather than mere conclusions of the witnesses." *Id.* Unlike in *Holst*, we have some specific data on which we rely -- the single-point calculations. We rule that the single-point calculations provide that sufficient basis.

HPP also argues that it is improper to rely on engineering calculations without a downward adjustment as called for in the Conservation Verification Protocols (CVP). (HPP-15.17; HPP-32.59.) HPP, however, offers no explanation of what downward adjustment would be appropriate or how to apply it. Without more, the Council does not find that this testimony constitutes sufficient evidentiary basis to disregard or to adjust the engineering calculations presented here. In any event, more significant than the foregoing adjustments is that each proposal is accorded similar treatment -- in that none are adjusted and the Council is relying on the best estimates available.

2. Measures and amount of firm offsets

OAR 345-23-010(2)(b)(C), which governs our evaluation of air emission offsets, consists of two parts. The first part addresses the activity the applicant proposes to undertake (the "measure") to offset air emissions. The second part states how we will evaluate the predicted results of the proposed measure. The rule provides in relevant part:

"(C) Firm offsets of air emissions shall be based on an estimate of emissions sequestered, avoided or displaced by the applicant's mitigation measures or cogeneration, provided such measures are guaranteed by an assurance bond or performance bond or can be made binding through other site certificate conditions. * * * In determining the amount of the firm offsets of air emissions, the Council shall consider the timing of the offset, the uncertainty, quantifiability and verifiability of the estimate of the amount of offset and the applicant's proposed measurement, monitoring and evaluation of the performance of the offset."

a. What is a "measure?"

Under the first part of the rule we must evaluate whether the request proposes measures that will sequester, avoid, or displace emissions, and whether the measures are guaranteed or can be made binding through site certificate conditions. Only proposals that meet these two criteria may be considered under the rule.

The applicants have made proposals that could be placed on a continuum with respect to the specificity of the proposal. They range from HPP's unspecific proposal to create a "mitigation fund" without identifying specific activities or programs on which the money would be spent, to UGC's very specific proposal to guarantee sequestration of a certain amount of CO_2 through conservation easements. Between those extremes are KG's proposals to fund specific offset programs, like tree planting under the Forest Resource Trust, and UGC's proposal to replace a certain number of inefficient woodstoves. The question is which of these proposals constitute a "measure" under the rule.

We conclude that the UGC and KG offset proposals each constitute a "measure" under the rule. The HPP mitigation fund proposal does not. In establishing this rule we intended for applicants to propose specific programs to offset the named pollutants. It was suggested to us during the rulemaking hearings that we simply solicit bids for a mitigation fund, and we did not adopt that approach. HPP's approach does not identify any activity to avoid, displace of sequester the pollutants. It does not constitute a "measure" under the rule.

UGC argues that the KG proposals may not constitute a "measure" because the activity KG proposes is not guaranteed and may not be made binding by site certificate conditions. UGC argues that KG proposes to guarantee only funding and not implementation or results. UGC 41.71-72. We disagree, at least in part.

Implementation will be required. But in keeping with our undisputed intent in adopting the rule, KG will not be held to particular results.

The "measures" KG proposes are to fund and to implement particular programs with specified amounts of money. The measures are capable of being made binding by site certificate conditions. We believe the site certificate conditions we have imposed will make implementation of those measures binding on KG. We have estimated in this proceeding the amount of the offset that is likely to result from these measures. But the rule clearly does not require that KG guarantee the results, i.e. the amount of pollutants that these measures will offset. Nor does the rule require that KG guarantee, or that we require through conditions, a specific number of units to be installed in order for a fund to implement a program to be a "measure."

UGC also argues that we may only consider growth in the proposed funds if the measures are made binding by site certificate conditions. As we have stated, we have made the measures binding by conditions. We consider the growth of the funds in determining the amount of emissions that will be offset by the measures.

The Council is convinced that it has made implementation of KG's measures sufficiently binding through the conditions proposed in Appendix A to this Order.

b. The amount of the offsets

The second part of the rule directs us to determine what amount of the proposed offset is "firm." The language of the rule clearly indicates that we may make some adjustment to the amount of offset claimed for the measure and for cogeneration. We do this by considering the rule's "evaluation factors," i.e. timing of the offset, the uncertainty, quantifiability and verifiability of the estimate of the amount of the offset, and the applicant's proposed measurement, monitoring and evaluation of the performance of the offset.

We begin with the following principles: (a) the Council is authorized to consider the evaluation factors in setting the amount of the offset; (b) we may use any appropriate method to evaluate and represent these factors; (c) we may consider any evidence in the record relevant to the factors; (d) the evidence offered by Dr. Carver and others with respect to uncertainty is admissible and material to the issue; and (e) the Council may, based on such testimony, establish numerical factors ("adjustment factors") that express the relative value of each proposed measure in light of the evaluation factors.

Timing

We address timing through our consideration of when the measures are proposed to begin to be implemented. As all the applicants call for implementation of the offsets at the time of construction or shortly thereafter, the issue of timing was not significant in this case. Furthermore, as discussed in the section below on discounting, we decline to give more credit to offsets that sequester carbon earlier, because the record does not establish the shape of the climate change damage function. Finally, we are not persuaded that the HPP plant will commence operations significantly before the other facilities. Although HPP has a site certificate, under its terms it may wait until 2000 before commencement of construction. This is approximately the same time frame for the other plants. HPP did not demonstrate it would be likely to commence before that date. Therefore we did not adjust the offset credit of any of the proposals to account for timing.

Uncertainty

Where there is significant uncertainty associated with a particular proposal, we have taken that into consideration in the "adjustment factors" to account for the risk that the offsets will not perform as predicted.

Quantifiability

Quantifiability is the degree to which the amount of emissions avoided, sequestered or displaced by the offset measure may be accurately quantified, and what that amount is. We have determined, starting with the applicant's assertions and evaluating other evidence in the record, what amount of emissions are likely to be offset. We estimate the emissions offset based on the record as a whole.

Verifiability

The verifiability of a proposal means the ability to determine that proposed measures have been undertaken and the degree to which they perform as expected.

C. Adjustment Factors

After considering each of the evaluation factors noted above, we assign an adjustment factor between 0 and 1 to each cogeneration and offset proposal. The adjustment factor is our assessment of the relative value of each proposal. An adjustment factor of 1.0 indicates that the proposal is highly certain, verifiable, quantifiable, and that the applicant has proposed appropriate measurement, monitoring and evaluation methods. A lower number indicates a lower relative value with respect to these elements.

The adjustment factors were not, and could not be, established or justified with mathematical precision. These considerations cannot be quantified with precision. The adjustment factors are a reasonable means of representing the relative values identified by the testimony and evidence for each proposal.

With respect to each proposal, testimony was offered identifying considerations relevant to the certainty or likelihood that the proposal would perform as expected. Arguments were offered to rebut alleged uncertainties. OE assigned each proposal a numerical adjustment factor that represents OE's evaluation of the relative uncertainty of the proposal taking those considerations into account.

The hearing officer found that the adjustment factors offered by OE were speculative and that there was insufficient underlying information to support the suggested factors, stating that "OE failed to clearly articulate the reasons for the adjustment factor or to offer or rely on evidence to support a given adjustment factor." (HO-15.14).

The hearing officer is correct that if a party offered an adjustment factor that was purely subjective, and the witness offered no explanation for its derivation, we should give it no weight. However, that is not the case with the adjustment factors suggested by OE or the factors that we adopt. Testimony and evidence were submitted concerning various elements of each proposal. We are authorized to consider the information relevant to the evaluation factors provided by OE and other parties and make our own judgment as to the relative value associated with each proposal.

The hearing officer was also concerned that use of adjustment factors would allow a decision-maker to side-step the decision whether an offset measure is "firm." But as we stated above, the rule clearly contemplates that we might adjust the amount of the offset based on the factors set forth in the rule, i.e. we might conclude that some amount other than that claimed by the applicant is the amount of offset that is "firm." "Partial credit," as it was characterized by the hearing officer, is authorized under the rule.

1. Discounting

As noted above, OAR 345-23-010(2)(b)(C) directs the Council, in considering the amount of the firm offsets of air emissions, to consider the timing, uncertainty, quantifiability and verifiability of the amount of each offset. HPP has proposed that we use "discounting" in our consideration of the timing of offsets. (HPP-15.24) The hearing officer proposed the use of discounting, of both emissions and offsets, as a means to compare the projects and to account for future uncertainties. (HO-15.15-16) We conclude that discounting is inappropriate for this proceeding, is not helpful to the analysis of individual proposals, and does not aid in comparing proposed offset measures. Further, we conclude that the lack of information in this case on the relative damages of CO2 over time (the climate change damage function) makes the choice of a zero discount rate reasonable.

First, we note that discounting is not mandated either by statute or our rules. Expert testimony is in agreement that use of discounting requires a policy choice by the decision-maker. Ms. Wayburn testified that "whether or not you apply a discount rate is a matter of public policy." (TR 740). Use of discounting requires a decision to value later emissions less than earlier emissions. (HPP-15.21; KG-31.71-74) Use of a discounting procedure "requires that the decision maker decide the relative value of actions taken in the future compared to actions taken today." (HPP-15.22) Although use of discounting may be within our discretion, we decline to adopt it for this proceeding.

As Mr. Richards testified, the decision to differentially value emissions over time requires antecedent decisions concerning the "climate change damage function" and the likely cost of emission reductions over time. (Tr 826.). The "climate change damage function" refers to "the relationship between concentrations of atmospheric gases, resulting climate change, and associated economic and ecological damage." (KG-31.72.). We agree with Dr. Trexler that those relationships are not well understood. (KG-31.72). Consequently, we decline to draw conclusions regarding the likely cost of emissions reductions or offsets over time, or to value particular emissions differently from others.

We recognize that discounting has been applied by other decision-makers in other proceedings. However, the context of discounting in other proceedings does not necessarily provide guidance for our determinations. For example, although the Public

Utility Commission ("PUC") mandates discounting for monetized air emissions in utility least-cost plans, the purpose of least-cost plans is to estimate the total resource cost (TRC) of utility activities. In this proceeding, we are not attempting to calculate TRC, but to compare proposed projects. We adopted monetizing of emissions for this proceeding as a means to evaluate CO_2, NO_x and PM-10 emissions collectively, and to fairly compare proposed facilities that would generate different amounts of electricity.

Discounting does not assist our analysis of individual projects. The hearing officer proposed discounting as a means for "accounting for uncertainties or risks that arise in the future." (HO-15.15.17) We conclude that discounting would not aid our analysis. The use of a single discount rate for all offset proposals, regardless of the specific project and the uncertainties of that proposal, would not fulfill our responsibility to evaluate the uncertainty associated with each individual project. Use of a general "blanket" discount rate would treat all proposed offset projects the same. To do so implies a decision that all of the proposed projects are equally uncertain over time. In fact, we believe the record clearly establishes that each offset proposal has specific and unique associated uncertainties. Therefore, we choose to evaluate each project on its own merits, according to the specific nature of the project. A single discount rate would not accomplish that individualized evaluation.

Discounting is also not necessary for a fair assessment and comparison of the proposed offset projects. To the contrary, if we adopted discounting without a clear policy foundation, and without a decision on the climate change damage function of emissions and offsets, we would be unfairly appreciating some offsets while devaluing others. We conclude that, for the purposes of this proceeding, not applying a discount rate or, in effect, a zero discount rate permits a fair comparison of the proposed offsets. As Mr. Richards testified: "[a] discount rate of zero is equivalent to not discounting because the effect is that the future tons -- the value of future tons are not reduced relative to the value of current tons reductions." (Tr 827.) The use of any positive discount rate other than zero percent would require a policy decision by the Council that offsets accomplished in the future are less valuable than offsets performed in the near term. We decline to make such a decision for this proceeding.

By declining to value present emission offsets differently from future offsets, we permit an equitable comparison of the projects. We note that all applicants proposed to undertake the bulk of their CO_2 offsets within the same basic time frame, so there is no fundamental difference in the patterns of CO_2 benefits.

All applicants propose to begin their offset projects within a few years after the facility begins operation; none have proposed to delay implementation. We have established a 100 year horizon for evaluation of offset proposals, although some proposals offer benefits that will likely continue into the future. Valuing all offsets equally within the identified time frame provides us with an equitable basis for comparison.

As this proceeding has demonstrated, the use of discounting is controversial under the best of circumstances. There is no clear consensus of expert opinion that discounting should be used at all. (KG-31.72) Similarly, there is no consensus of opinion as to the appropriate discount rate to apply. Mr. Richards noted that rates between 2 and 10 percent would be justified. (HP-15.26) Dr. Trexler testified that rates employed by the IPCC range from 0.5 to 3.0 percent, and included discussion of negative discount rates. (Tr 570.)

As we discussed above, the purpose of discounting is to express a preference for emission offsets at some particular time. The particular discount rate in turn expresses the strength of that preference. For example, a discount rate of 4 per cent reduces the value of an offset--and the complementary cost of emissions--by 50 percent after eighteen years, by 70 percent after 31 years, and by 90 percent after 60 years. Given the long range nature of climate risk from CO_2 emissions, this seems unreasonable. Although lesser discount rates have lesser impacts, its not clear that using them will improve the comparison of the alternative proposals in this case. The discount rate suggested by general environmental policy analysis or the rate of return of certain government bonds is irrelevant to our decision in this proceeding.

2. Permitting UGC or KG to target operations for the year 2000

Both UGC and KG anticipate commencing operation of their proposed plants in the year 2000. The record indicates that HPP is on a similar time frame. HPP's site certificate requires that it commence construction by November, 2000 and that it complete construction by January 1, 2003. UGC and KG propose using new turbine technology that will be ready for UGC and KG by the year 2000.

HPP objects to stretching the shelf life of the exemption to the year 2000. HPP contends that the exemption was intended to have a short shelf life and that the Council should require a prevailing applicant to commence operations before the year 2000. HPP also argues that because it has a site certificate it must be ready to order a turbine within the next year, and that it gives an unfair advantage to UGC and KG to credit them with use of turbine technology that will not be available until 2000.

In developing the exemption rule, the Council expressly rejected placing any limit in the rule on the shelf life of the exemption. (Rulemaking record, at 197-200.) The Council preferred to maintain flexibility based on the proposal, specifying the shelf life in the site certificate and including the possibility of extending the exemption's termination date. (Rulemaking record, at 199-200.) Furthermore, a four year shelf life is entirely consistent with our past practices in issuing site certificates. As HPP's site certificate allows construction to begin as late as 2000, HPP is not disadvantaged by this approach.

3. Calculating emissions based on new and clean operations at 100% capacity

OE has used the following standard operating conditions to determine and compare each facility's direct emissions: (a) each facility will operate at full load, maximum annual (new and clean) net electric energy output; (b) 100 percent capacity; (c) average site conditions; and (d) specified maximum hours on primary and secondary fuel based on applicant responses. Each party provided fuel consumption and emissions data based on new and clean conditions for the combustion turbines being proposed, and OE calculated emissions on that basis.

HPP has argued that a 100% load factor, year round 24 hours per day (8760 hours per year) is unrealistic and should not be relied upon in calculating emissions. (HPP-32.33.) Rather, HPP argues that emission calculations should be based upon some prediction of expected, actual performance.

The purpose of this proceeding, however, is not to accurately predict actual operating conditions but to develop a reasonable criteria for determining which proposal is the most environmentally clean. Nothing in the record suggests a difference in how the three proposed plants will be maintained or differences in terms of the frequency or manner of start up or shut down. (Tr at 346.) And, each plant is expected to be fully dispatchable. (Tr at 347.) Thus, it is fully reasonable to use the assumptions described above as a base case for comparison to determine the relative environmental effects of the each proposal.

4. Dilution of offsets

In is posthearing brief KG objected to this approach on the grounds that it diluted offset measures. KG has argued that calculating gross emissions on this basis overstates operating efficiencies and, in turn, understates gross emissions from turbine operations on a per kWh basis. The net effect is to dilute the actual impact of emissions offsets on a per KWh basis. Furthermore, KG argues, this dilution understates the differences between its proposal with greater CO_2 offsets and the competing proposals with lesser CO_2 offsets. (KG-37.160.)

While theoretically true, KG did not offer factual support to correct for this dilution effect. KG noted only that it expected to operate its plant at 85% capacity. There is no record evidence to show whether other plants expected to operate their plants at the same capacity, a lesser capacity or greater capacity than did KG. If each of the proposed plants will operate at the same overall capacity, the dilution will be proportional to the total offsets.

As discussed below, KG has proposed proportionally larger amount of offsets then the other applicants. Thus, KG is impacted most by the dilution effect. Because we conclude, as discussed below, that KG's proposal has the least detrimental impact on the environment, we need not correct for this dilution effect.

5. Tabular form of calculations

At our request the Office of Energy has prepared spreadsheets showing the necessary calculations for this proceeding. The spreadsheets reflect our decisions on all issues. The spreadsheets are attached to this order.

D. Basic Assumptions Regarding Gross Emissions

Based, in part, on resolving some general issues raised by the parties, we make the following basic assumptions regarding the calculations of gross emissions:

1. Standard for calculating gross emissions

OAR 345-023-010(2)(b)(B) states: "CO_2 emissions from the facility shall be based on the annual fuel input to the facility times the carbon content of the fuel." The annual fuel input is calculated by multiplying annual energy produced by the appropriate heat rate.

Annual energy (kWh/yr) is calculated by multiplying nominal generating capacity (kW) by the hours of operation per year (assumed for all applicants to be 8,760, see below). Nominal generating capacity is the maximum kilowatts that may be produced, less electricity and other forms of energy used for auxiliary uses, such as system cooling, compressors and other uses.

The heat rate (Btu/kWh) expresses the amount of energy necessary to produce the nominal generating capacity. Multiplying the annual nominal energy by the heat rate provides the amount of annual fuel use. The formula used for calculating annual fuel use is: (nominal power) X (hours/year) X heat rate; or (kW) X (8,760.) X (Btu/kWh). The resulting figure expresses the total annual fuel use in MMBtu/hr.

Total annual CO_2 use is calculated by multiplying total annual fuel use by the carbon rate for each fuel (see below), which yields the total annual pounds of carbon produced. CO_2 is then calculated by multiplying pounds of carbon by 3.667. OAR 345-21-010(2)(b)(B).

NO_x and PM-10 emissions are calculated by using the emission rate for each turbine. The emission rate, in lb/kWh, is multiplied by total annual energy produced to yield total emissions in tons per year. Lifetime emissions are determined by extending the annual emission rates for the life of the project.

The emissions are then monetized by multiplying the lifetime total of the emissions by the rates provided in table I of OAR 345-01-010(35).

2. Standard for calculating net emissions

Each applicant proposed to displace or offset air emissions through cogeneration projects, other energy displacement projects and programs for carbon sequestration. The Council evaluated the proposed displacement and offset programs based upon the standards in OAR 345-21-010(2)(b)(c). Application of the standards yielded net emission reductions.

Total net emissions for each facility were calculated by subtracting the net emission reductions that will be achieved by each program from the project's estimated gross lifetime emissions. Those values were then monetized as described above to yield the net monetized value of the air emissions for each project.

3. Heat rate

Each project will have a different heat rate, based upon the characteristics of the site, the configuration of the facility, the turbine, and other factors. OE requested that each applicant calculate maximum net electrical output and fuel input, including duct burning and all other auxiliary energy uses. The applicants each responded with calculations which addressed energy used by the facility, including energy required for system cooling, gas compressors, duct burning and all other auxiliary uses.

Arguments were made that additional amounts of energy might be used by some applicants for gas compressors and duct burning. Those arguments are discussed below. OE staff concluded and Council agrees that the heat rate provided by each applicant includes the total fuel use by each facility for all purposes.

4. Carbon rate

The carbon rates used by OE are taken from the handbook published by the United States Environmental Protection Agency. OAR 345-23-010(2)(b)(B). The rate applies whenever the applicable fuel is used, regardless of the facility.

5. Turbine degradation

All calculations of the projects' electrical production, heat rate, energy use and air emissions were based on each turbine being in "new and clean" operating condition. The figures derived from "new and clean" conditions were then extended over the assumed thirty year project life, without attempting to estimate normal turbine degradation. Ignoring normal degradation of efficiency by use of new and clean conditions tends to understate actual emissions.

Testimony was introduced contending that the turbines proposed for use by KG and UGC might degrade more rapidly than other turbines. (HPP-17.6.) UGC and OE presented testimony rebutting those assertions. UGC testified that turbine heat rate degradation is primarily a function of compressor fouling from impurities in intake air and the maintenance that is done to remove contaminants on the compressor. (Tr 298.) UGC testified that there would be only very small differences between the fouling characteristics of different turbines based on compressor design. (Tr 259.) UGC testified that actual heat rate varies according to maintenance practices and site conditions. (Tr 328.) HPP did not provide evidence that maintenance practices would be different between proposals nor that purity of intake air would be different at the proposed sites. UGC also testified that there was no reason to believe that heat rate degradation due to maintenance and site conditions would be different for the GE 7H machine as compared to other GE machines. (Tr 328.) OE testified that under consistent assumptions it would not expect heat rate degradation between machines to be more than ten percent different. (Tr 352.)

Based on the testimony of Mr. Corman and the testimony of Dr. Jones, we conclude that the performance degradation of each of these machines is primarily driven by compressor fouling and is likely to be the same for each machine. The Council finds it is reasonable to assume the deterioration of heat rate due to normal turbine degradation would not be different between any of the turbines proposed and therefore that heat rate under new and clean conditions is a reasonable estimate of relative turbine efficiency.

6. Load[1] factor

Each of the proposed projects was designed and intended to be fully dispatchable, that is, available for energy production at all times. OE therefore calculated annual project energy production, fuel use and air emissions based upon each project operating at 100 per cent capacity for 8760 hours per year. The Council finds this to be a reasonable assumption for the purposes of this proceeding.

7. Project life

Based on the proposals, OE concluded that all of the proposals were designed to operate for thirty years. OE therefore calculated total lifetime project energy production, fuel use and air emissions based upon a thirty year project life for each facility. We find this to be a reasonable assumption in this proceeding.

V. FINDINGS OF FACTS: AIR IMPACTS OF THE HERMISTON POWER PROJECT ONE AND TWO UNIT PROPOSALS

In its Request For Exemption, HPP proposed both a two unit and a one unit project. (HPP Request 2.) HPP first requested the 500 MW exemption for the two unit project. If it was determined that the two unit project would not be awarded the exemption, HPP requested the one unit project be evaluated in the alternative. (HPP Request 2.)

A. Facility Configuration

[1] We use the term "load factor" throughout this order to mean the product of the hours of operation times the capacity of the facility on an annual basis. That figure is sometimes referred to in the industry as the "capacity factor."

HPP's proposed two unit combined-cycle combustion turbine electrical generating facility will have a nominal electric generating capacity of 470 MW (net) at annual average conditions. The project will include two combustion turbines, two heat recovery steam generators (HRSG), two steam turbines and two generators. (HPP Request 2.) The one unit proposal will consist of a single combustion turbine, HRSG, steam turbine and generator. It will have nominal electric generating capacity of 232 MW. (HPP Request 2.) Under either proposal, the electrical generating facility will be fully dispatchable, meaning it will be capable of operating for 8,760 hours per year. (HPP-9.2.)

Under either proposal, the generating facility will provide steam to a potato processing plant, displacing emissions from the potato plant's existing boilers. (HPP Request 5.) HPP also proposes a "Mitigation Fund" that will be used to reduce CO_2 emissions from other sources and/or sequester CO2. (HPP Request 5.)

B. Generating Capacity

1. Fuel

The primary fuel for the project will be natural gas. (HPP Request 4.) HPP proposed use of distillate oil as a backup fuel for short periods when natural gas is unavailable. (HPP Request 4.) Based on the Request, and to make the HPP proposal consistent with staff's original assumptions about KG's oil use, OE assumed the facility would use oil 720 hours per year. (OE-11.10.)

HPP provided calculations of plant performance and air emissions based on 100 per cent use of natural gas for fuel. (HPP-9.5.) HPP testified that HPP's ACDP does not allow the use of distillate oil for fuel. (HPP-25.1; HPP Request, Exhibit 4, at 7.) The permit states: "The two combustion turbines and two duct burners shall burn only pipeline quality natural gas." We find the HPP generating facility is prohibited from burning distillate oil by the Oregon Department of Environmental Quality ("DEQ") and will use only natural gas for fuel.

UGC asserts that evaluating HPP based on no use of oil is an impermissible amendment. We disagree. HPP's Request was ambiguous on this point. The request stated that the facility would use "distillate backup for short periods when natural gas is not available." HPP Request p. 4. But the Request also includes as Exhibit 4 a copy of the Air Contaminant Discharge Permit from DEQ that prohibits use of distillate fuel. Given that ambiguity, HPP's clarification was permissible.

2. Nominal power

HPP estimates of project generating capacity, fuel input, power output and emissions were based on use of the ABB GT24 combustion turbine. (HPP Request, Vol 2, Exhibit 3; HPP-9.3.) OE accepted the ABB GT24 figures for the basis of OE calculations. (OE-12.9.)

Based on use of the ABB GT24 turbine, the proposed two-unit facility will have a nominal generating capacity, with no thermal energy to cogeneration, of 476,400 kW, or 238,200 kW for each turbine. (HPP-9.1.) Nominal generating capacity that includes delivery of thermal energy to the steam host at the rate of 85,200 lbs/hr will be 469,934 kW. This includes 231,734 kW for the unit producing 85,200 lb/hr of steam for the processing facility, and 238,200 kW for the unit that will not produce steam. (HPP Request, Vol 2, Exhibit 3; OE-35.5-6)

The proposed one unit facility will have nominal generating capacity of 231,734 kW at a steam extraction rate of 85,200 lb/hr. (OE-35.5)

3. Energy output

On the basis of 469,934 kW nominal generating capacity, the two unit facility will produce annual energy of 4,116,621,840 kWh/yr while making cogenerated steam. (OE-36.8.) The one unit facility will produce annual energy of 2,029,989,840 kWh/yr. (OE-35.5.)

4. Heat rate

HPP asserts the ABB GT24 turbine will have a heat rate, without steam extraction, of 6837 Btu/kWh. (HPP Request Vol 2, Exhibit 3.) The heat rate with steam extraction at 90,000 lbs/hr will be 7050 Btu/kWh. (HPP Request Vol 2, Exhibit 3.) From that data, OE extrapolated a heat rate with steam extraction at 85,200 lb/hr of 7,028. The project will use two turbines simultaneously, one of which will make steam for the Simplot factory. OE estimated a combined heat rate of 6,932 Btu/kWh. (OE-36.8.) The heat rate was not disputed, and Council adopts OE's conclusions.

5. Auxiliary uses -- Gas compressors

Nominal generating capacity for the two unit facility is based on the assumption that the estimated auxiliary load includes all auxiliary energy uses. UGC asserts that additional pipeline compressors will be required to deliver natural gas at the pressure required for the ABB GT 24 turbine. (UGC-12.4, 12.5.) HPP testified that the gas suppliers will normally supply gas at a minimum pressure above that required by the ABB GT 24 turbine. (HPP-13.6; HPP-25.6-7.) HPP testified that even if compressors are required, they will be used infrequently and will not significantly increase overall project air emissions. (HPP-25.9.)

We find that extra gas compression will probably not be required. Even if extra compression is required, we find the amount of use will be minimal and will not affect overall facility air emissions.

6. Auxiliary uses -- Duct burner emissions

For the two unit facility, HPP proposes to use two HRSG's that will produce steam from the combustion turbine exhaust gases. The one unit facility will use only one HRSG. The steam will be expanded in steam turbines to produce additional electricity. Some of the steam will be delivered to the Simplot potato factory as part of the cogeneration process. (HPP Exhibit B, at 6.) Each HRSG will have a natural gas fired duct burner to maintain the steam turbine electrical output during periods of high process steam flows to the potato plant. (HPP Exhibit B, at 7.)

HPP's ACDP allows use of up to 7,300 hours per year of duct burning. (HPP Request Vol 2, Exhibit 4, at 3-5.) HPP and OE estimates of project CO_2 emissions did not account for the emissions from the duct burners. (HPP-9.4.)

HPP testified that duct burning would be used only in temporary unusual circumstances (HPP-9.4.), to supply short-term peak steam loads to Simplot through the cogeneration process. (HPP-25.5-6.) HPP asserted that any extra CO_2 that may be emitted from duct burning would be offset by displaced CO_2 that would have been emitted from the Simplot boilers. (HPP-25.5-6.)

The Council concludes that any air emissions caused by short-term use of duct burning would be offset by displaced emissions from existing steam boilers.

7. Annual energy use

Based on the heat rate and energy output figures set out above, and assuming cogeneration, we find annual natural gas use for the two unit facility will be 28,538,340 MMBtu/yr. (OE-36.8.) Annual natural gas use for the one unit facility will be 14,266,630 MMBtu/yr. (OE-35.5.)

8. Emissions

a. Carbon dioxide emissions

Using a natural gas carbon rate of 31.9 lb/MMBtu and a CO_2 rate of 116.97 lbs/MMBtu, annual project CO_2 emissions for the two unit facility will be 1,669,169 ton/yr. (OE-36.8.) Over the 30 year life of the project, CO_2 will total 50,073,057 tons. (OE-36.1.)

For the one unit facility, annual CO_2 emissions will be 834,436 ton/yr. (OE-35.5.) CO_2 emissions over 30 years will total 25,032,962 tons. (OE-35.1.) The Council concurs with OE's estimates.

b. Nitrogen oxides emissions

OE calculated NO_x emissions using the values established above for nominal power use, annual nominal power use, primary fuel use and secondary fuel use. OE estimated the NO_x emission rate for natural gas, derived from the applicant's Request, at 0.000136 lb/kWh. (OE-36.8.)

Based on annual energy production of 4,116,621,340 kWh/yr, OE estimates annual NO_x emissions will be 280 ton/year for the two unit facility. (OE-36.8.) NO_x emissions over the 30 year life of the project will total 8,400 tons. (OE-36.1.)

For the one unit facility, NO_x emissions with 140 ton/year or 4200 tons over the life of the facility. We find OE's estimate of NO_x emissions to be persuasive.

c. PM-10 particulate emissions

PM-10 emissions are calculated by using the values established above for nominal power use, annual nominal power use and primary fuel use. OE estimated the PM-10 emission rate for natural gas, derived from the Applicant's Request, at 0.000036 lb/kWh. (OE-36.8.) OE estimates annual PM-10 emissions will be 74 tons/year for the two unit facility. (OE-36.8.) OE estimates PM-10 emissions over the 30 year life of the project will total 2,220 tons. (OE-36.1.)

For the one unit proposal, OE estimates annual PM-10 emissions will be 37 tons/yr. (OE-35.5.) Over thirty years, PM-10 emissions will total 1,110 tons. (OE-35.1.) We find estimates of PM-10 emissions to be persuasive.

C. Cogeneration

1. Proposal

HPP proposes to supply steam from the facility to a Simplot potato processing facility at the rate of 85,200 lb/hr. (HPP Request 5.) This will displace steam and, therefore, emissions now produced by existing boiler Simplot boilers. HPP proposes to cogenerate the same amount under both the one-unit and two-unit proposals.

2. Evaluation factors

a. Timing

HPP and Simplot have entered into a cogeneration agreement (HPP Request Exhibit 7.) Under the agreement, Simplot is committed to the exclusive use of steam generated by HPP.

As proposed, cogeneration would take place concurrently with and as part of power generation.

b. Quantification of emissions displaced

Cogeneration by its very nature is readily quantifiable. As discussed below, engineering calculations can be undertaken to ascertain the amount of energy generation and resulting emissions that are displaced.

i. Amount of steam to be supplied

HPP estimated average annual steam use at Simplot at 79,000 lb/hr. (HPP Request Exhibit 5.) HPP provided evidence that Simplot was expanding the Simplot potato processing plant and would increase steam use by approximately 7 percent by the time the HPP generating facility was operating. (HPP Request Exhibit 6.) HPP therefore estimated steam flow from cogeneration will be 85,200 lbs/yr. (HPP Request Exhibit 5; HPP-9.7.)

We find HPP will provide an average steam flow of 85,200 lbs/hr to Simplot.

ii. Existing boiler emissions displaced

OE estimated the amount of boiler fuel and emissions displaced based on a higher heating value (HHV) basis. (OE-11.11.) HPP and OE disagree about the HHV efficiency rating of the existing boiler. HPP used a boiler efficiency of 80 percent to calculate fuel displaced on a lower heating value (LHV) basis. (HPP-2.11.) An efficiency of 80 percent (LHV) corresponds to an efficiency of approximately 72 percent higher heating value (HHV). (OE-11.11.) Based on that rating, the cogenerated steam would displace 1,090,227 Btu/yr. (OE-11.11.)

OE assumed the 72 percent HHV rating was erroneous because that was a very low HHV rating and because HHV efficiencies of 80 percent and higher are common. (OE-11.11.) OE calculated

displaced fuel based on an 80 percent HHV rating at 981,757 mmBtu/yr (OE-36REV.8, OE-35.5).

HPP testified the measured stack gas oxygen content and exit temperature suggested boiler efficiencies in the range of 79 to 85 percent LHV. However, the **ASHRAE Handbook, 1981 Fundamentals**, the standard industry reference manual, shows an 81 to 83 percent HHV for a boiler with Simplot's exit temperature and exhaust gas oxygen content. (OE-27.1.) During its presentation on exceptions, HPP abandoned its position on LHV and agreed that HHV was more appropriate. Based on the measurements of the boiler stack oxygen content and exit temperature and the ASHRAE handbook, we find the Simplot boilers have an efficiency of 80 percent HHV.

iii. Emissions displaced by cogeneration

(1) CO_2 displaced

HPP assumed that, although Simplot boilers use both natural gas and biogas, cogeneration will displace only natural gas. (HPP-2.2-3.) We accept that assumption.

Based on displacement of 981,757 Btu/yr and a carbon rate of 31.9 lb/MMBtu for natural gas, the cogeneration process will displace 57,422 ton/yr of CO_2. (OE-36.8) OE estimates a total of 1,722,649 tons of CO_2 will be displaced over the 30 year life of the facility, before adjustment. (OE-36.11) We find that estimate to be persuasive.

(2) NO_x displaced

Based on the weighted NO_x rate of 0.11 lb/MMBtu, we estimate the cogeneration process will displace 55 ton/yr of NO_x. (OE-36.8) OE estimates NO_x displaced over the 30 year life of the project, before adjustment, will total 1649 tons. (OE-36.11) We find this estimate to be persuasive.

(3) PM-10 displaced

Based on the weighted PM-10 rate of 0.00238 lb/MMBtu, OE estimates the cogeneration process will displace 1.2 ton/yr of PM-10. (OE-36.8.) OE estimates PM-10 displaced over the 30 year life of the project will be 35 tons, before adjustment (OE-36.11.) We agree and accept that estimate.

c. Uncertainty

HPP has contracted to deliver steam to Simplot, and Simplot has committed to purchase steam from HPP. There is, however, some possibility that the Simplot plant may not use the full amount of steam for the 30 year life of the project. Moreover, the steam sales agreement between HPP and Simplot does not provide Simplot with any specific remedies in the event HPP does not sell it steam. The relationship between HPP and Simplot may provide economic incentive not to cogenerate in the future. Because Simplot and SimGen are related corporations, Simplot may be willing to ignore violations of the contract if it were to SimGen's advantage to do so. In addition, if the processing plant is sold, there is no guarantee that another purchaser will continue to buy steam from HPP.

d. Verifiability

The calculation of steam consumed by Simplot and the amount of power generation displaced at Simplot is readily ascertainable. Consequently, the amount of emissions displaced through cogeneration can also be determined.

3. Adjustment factor

Based on the foregoing, we find that an adjustment factor of 0.8 is reasonable for this proposal.

4. Net emissions displaced

a. CO_2 displaced

As stated above, the cogeneration process will displace 1,722,649 tons of CO_2 before adjustment. (OE-36.11) Applying the

0.80 adjustment factor, the cogeneration process will displace 1,378,119 tons of CO_2 over the life of the project. (OE-36REV.1).

b. NO_x displaced

As stated above, over the 30 year life of the project the cogeneration process will displace 1,649 tons of NO_x. Applying the 0.8 adjustment, the cogeneration process will displace 1,319 tons of NO_x. (OE-36 REV.1)

c. PM-10 displaced

As stated above, over the 30 year life of the project the cogeneration process will displace 35 tons of PM-10, before adjustment. Applying the 0.8 adjustment factor, the cogeneration process will displace 28 tons of PM-10. (OE-36REV.1)

D. Mitigation Fund

In addition to the cogeneration process, HPP proposes to establish and maintain a CO_2 "Mitigation Fund." The Fund would be under the sole control of OE. It would be administered on behalf of the Council by OE and used to finance research and/or programs for greenhouse gas mitigation. (HPP Request 14.) HPP proposes to deposit $250,000 yearly into the Fund. Deposits into the Fund over the 30 year life of the project will total $7,500,000 in 1995 dollars. (HPP Request 14.)

OE assumed the HPP Mitigation Fund would offset zero CO2. (OE-11.9.) This assumption was based upon the failure of the proposal to identify any specific mitigation programs or measures to which it could assign a numerical value. For this reason, OE concluded that the results of the Mitigation Fund could not be quantified, and therefore could also not be analyzed for uncertainty, verification, measurement and monitoring. (OE-11.9.) OE found the proposal was unresponsive, and assigned the mitigation Fund an adjustment factor of 0.0. (OE-11.9, OE-36.7.)

HPP asserts that the amount of CO_2 displaced by the Mitigation Fund can be evaluated by multiplying the Mitigation Fund contribution times a CO_2 unit mitigation cost (the cost of offsetting or sequestering on ton of CO_2.) This figure may then be used to calculate a tons per megawatt-hour reduction credit (HPP Request 8.) and the monetized value of the offset. (HPP Request 9.)

Using HPP's proposed CO_2 mitigation cost of $81/ton, OE estimated the fund would offset 92,600 tons of CO_2 (OE-11.9.), with a value of approximately 0.01 mils/kWh, based on the energy produced by the two unit facility. (OE-11.10.)

KG performed a similar calculation, based on an assumed CO_2 offset value of $10/ton. (KG-25.8.) KG estimated the fund would result in 139,500 and 279,000 tons of CO_2 offsets under the one and two unit facility options. KG estimated the monetized value of these offsets would be 0.025 mil/kWh and 0.024 mil/kWh respectively for the one and two unit design options. (KG-25.8.)[2]

We have already concluded, earlier in this order, that the HPP mitigation fund proposal does not constitute a "measure" under the rule. Even if it did meet that threshold requirement, the Council finds that the HPP proposal provides no basis for quantifying or evaluating the Mitigation Fund air emission program. The estimated offsets do not provide a basis for evaluating the uncertainty, verification, measurement and monitoring of the fund. Council therefore concludes that the proposal will result in zero net displacement of air emissions.

E. Total Monetized Net Emissions

For the two unit proposal, CO_2 emissions over the life of the facility will total 50,073,057 tons. (OE-36.1) For the one unit proposal, lifetime facility emissions will be 25,032,962 tons. (OE-35.1) The cogeneration process will displace 1,378,119 tons. The Mitigation Fund is credited with offsetting zero tons. (OE-36REV.1)

For the two unit proposal, total net CO_2 emissions over the 30 year life of the facility will be 48,694,938 tons. (OE-36.1) Total net CO_2 emissions for the one unit facility will be 23,654,843 tons. (OE-35.1).

NO_x emissions over the life of the two unit facility will total 8,400 tons. (OE-36.1) For the one unit facility, lifetime NO_x emissions will total 4,200 tons. (OE-35.1). The cogeneration process will displace 1,319 tons. The Mitigation Fund will displace zero tons. (OE-36REV.1)

For the two unit proposal, total net NO_x emissions over the life of the project will be 7,081 tons. (OE-36REV.1) Total net

[2]Even if credited with this offset, HPP's monetized net emissions are significantly greater than KG's.

NO_x emissions for the one unit facility will be 2,881 tons. (OE-35.1).

For the two unit proposal, PM-10 emissions over the life of the facility will total 2,220 tons. (OE-36REV.1) For the one unit facility, lifetime PM-10 emissions will total 1,110 tons. (OE-35.1) The cogeneration process will displace 28 tons net or 35 tons gross. (OE-36REV.1) The Mitigation Fund is credited with displacing zero tons.

Total net PM-10 emissions over the life of the two unit facility will be 2,192 tons. (OE-36.1) Total net PM-10 emissions over the life of the one unit facility will be 1,082 tons. (OE-35.1) (OE-36REV.1).

Based on the project emissions, energy produced and values set out in OAR 345-01-010(35), we find the net monetized value of HPP's air emissions for the two unit proposal will be 4.08 mils/kWh. (OE-36.1). We find the total net monetized value of air emissions for the one unit proposal will be 3.99 mils/kWh. (OE-35.1).

VI. FINDINGS OF FACTS: AIR IMPACTS OF THE KLAMATH COGENERATION PROJECT

A. The Proposal

KG proposes an electrical generating facility using a single, combined-cycle combustion turbine with nominal electric generating capacity of 305 MW. (KG Request 1-1.)[3] The energy facility will include a combustion turbine generator, a heat recovery steam generator and a steam turbine generator. The turbine will be fully dispatchable, meaning it is capable of operating for 8,760 hours per year. (KG Request 2-1.)

The primary fuel for the energy facility will be natural gas. (KG-3.2.) Distillate oil will be used as a secondary, backup fuel. (KG-3.5.) The energy facility will make process steam available to a plywood and particle board manufacturing facility owned by Weyerhaeuser Co. (KG Request 1-1.) KG also proposes to offset CO_2 and PM-10 emissions through solar rural electrification, the Oregon Forest Resources Trust, displacement of fossil fuels through use of methane, and expansion of the existing Klamath Falls geothermal system. (KG Request 1-2.)

[3]KG's Request for Exemption was titled "Application for Exemption from Need for Facility Determination" and is referred to here as "KG Request."

B. Generating Capacity

1. Turbine availability

OE estimates of the KG energy facility nominal electric generating capacity, fuel input, power output and emissions were based on data for the MHI/Westinghouse 501G combustion turbine that was provided by KG. (KG Request 2-4.) The 501G turbine, much like the GE 7H turbine that will be used by the UGC project, will use advanced technological and design features. (HPP-17.6; KG-10.1.) However, the 501G turbine has been commercially offered, with deliveries and installation expected to begin in late-1996. (KG-10.1.) KG testified that it expected to have the project commercially operating by the year 2,000. (Tr 243-44.)

HPP asserted that, because KG did not provide specific design information, HPP could not verify the 501G turbine will be available for use in the KG facility as proposed. (HPP-17.11; HPP-19.2-4.) Based on that uncertainty, HPP argued the heat rate for KG should be based on the heat rate of the manufacturer's most efficient commercially operating machine. (HPP-19.7.)

HPP presented testimony that the 501G technology was not currently available and had never been tested in operation. (HPP-17.1-6.) HPP also presented testimony that development of the 501G turbine presented significant design challenges and will require solving difficult technological problems, particularly involving the increased combustion temperatures and steam cooling system. (HPP-17.5-7.)

HPP also pointed to KG's unwillingness to commit to using the 501G turbine in its plant. (HPP-32.21 & 22.) KG's desire to maintain maximum flexibility in constructing the plant is understandable in that they wish to take advantage of any other advances between now and construction. (Tr 200 & 202.) What is important for this proceeding is that the Council be convinced that the technology will exist to achieve the output that KG proposes in the time frame that they propose.

HPP's testimony identified the uncertainties in the turbine design and construction. HPP, however, offered no persuasive evidence that the 501G turbine would not be available as advertised. The GE and Westinghouse turbines share common technological features and have common uncertainties. (HPP-17.3, 17.13.) UGC's expert James Corman, General Manager of Power Generation Systems for GE, testified that GE does not anticipate technical problems with the 7H turbine. He testified further that

GE does not make a machine commercially available until it is ready to move forward with the manufacture, installation and operation of that turbine. (Tr 310.) He stated his understanding that once a manufacturer announces commercial availability of a machine, it will stand by its claimed performance. (Tr. 311.) Westinghouse has announced commercial availability of the 501G turbine. (KG-10.1.)

Mr. Corman's testimony concerning the GE 7H turbine, and about industry practice with respect to commercial availability, supports our finding that the Westinghouse 501G machine is likely to be available and perform as specified within the time frame proposed by KG for operation of its proposed plant. Even HPP testified that it expected the 501G technology to be available within the time frame proposed by KG. (Tr 243-44.)

HPP also argues that the Council can not rely on conditions in lieu of proof that emission offsets are likely to be achieved. (HPP-32.34.) The Council agrees and bases its determination on evidence of record establishing the level of outcomes or results likely to be achieved.

Based on the testimony presented by KG, UGC and HPP, the Council finds that the Westinghouse 501G turbine will be commercially available for use in the KG project.

2. Fuel

KG proposes to use distillate oil as a secondary fuel for short periods of time when natural gas is not available. KG Request F-2.) KG requested permission to burn distillate oil for 720 hours in its ACDP. (OE-11.27.) Because of that, OE originally estimated that the project would burn oil for 720 hours per year. (OE-11.27.) KG subsequently presented testimony that its use of oil would be very limited (KG-30.2.) KG testified that its maximum oil use would be between 5 and 15 days per year. (KG-30.2; Tr. 358, 359.) UGC argued that to set KG's oil use at 360 hours would be an impermissible amendment. We do not agree. KG's application stated that its fuel use was "...not expected to exceed 720 hours per year..." (KG ASC F-3). Its later clarification of this statement is not inconsistent with the request and is therefore not an amendment. We find that KG use of oil would average no more than 360 hours per year equivalent to 15 days.

3. Heat rate

KG did not provide a heat rate for the project in its Application for Site Certificate or the Request for Exemption. We derive a heat rate for the project based upon the annual fuel input and energy output figures provided by KG. (KG-13.2 - 13.4.) We estimate the energy facility heat rate using natural gas, with cogeneration at 7,212 Btu/Kwh and without cogeneration at 6,795 Btu/Kwh. (OE-36.8, 36.9.) We estimate the project heat rate using distillate oil, with cogeneration, at 7,691 Btu/Kwh and without cogeneration, at 7,229 Btu/Kwh. (OE-36.8, 36.9.)

HPP asserted that there is uncertainty about whether the 501G turbine will meet the declared heat rate and emissions rates, because the 501G turbine relies upon unproven and untested technological developments. (HPP-19.6-7.) HPP also asserted that, due to the higher combustion temperatures and the steam cooling system proposed for the 501G turbine, there was a greater likelihood that the heat rate would degrade significantly over time. (HPP-17.7-17.8.)

In its evaluation of the proposed projects from HPP, UGC and KG, OE used technical information from the manufacturers, including heat rates. All of the manufacturers are established and reliable providers of combustion turbines; their professional and commercial reputations depend on meeting equipment performance specifications and representations. (Tr 311.)

HPP's testimony identified the uncertainties in the turbine design and construction. As noted earlier, we are persuaded that the Westinghouse 501G machine is likely to be available and perform as advertised. As we stated in Section II.D.5 of this order, we also find that the performance of the three turbines proposed in this proceeding will not degrade at significantly different rates.

Based upon the evidence, the Council finds that the Westinghouse 501G turbine will meet the declared heat rate and that the 501G heat rate will not degrade significantly more than the other proposals over time.

4. Nominal power

We calculate the nominal power for each fuel by extrapolation from the tables provided by KG for net electric output for various steam extraction rates. (KG Request 2-7; OE-11.27.) For the reasons described in the discussion of KG's cogeneration, we find that a steam extraction rate of 200,000 lbs/hr is representative of average annual steam delivery over the 30 year life of the project.

Based on that steam extraction rate, we calculate that, when natural gas is used as fuel, nominal power without cogeneration will be 317,900 kw and with cogeneration will be 299,500 kw. (OE-

36.9; OE-36.8.) When distillate oil is used as fuel, we estimate nominal power at 323,000 without cogeneration and 303,600 kw with cogeneration (OE-36.9, 36.8.)

5. Annual energy use

Based on the foregoing, we find that the energy facility will use natural gas for 8,400 hours per year. (OE-36.8, OE-36.9.) Annual energy produced from natural gas, with cogeneration, will total 2,515,800,000 Kwh/yr. (OE-36.8.) Annual energy produced from natural gas, without cogeneration, will total 2,670,360,000 Kwh/yr. (OE-36.9.)

Based on use of distillate oil for 360 hours per year, annual energy produced with oil, with cogeneration, will total 109,296,000 Kwh/yr. (OE-36.8.) Annual energy produced from oil, without cogeneration, will be 116,280,000 Kwh/yr. (OE-36.9.)

Auxiliary uses

KG proposes use of a heat recovery steam generator (HRSG) that will produce steam from the combustion turbine exhaust gases. The steam will be expanded in a steam turbine to produce additional electricity. Some of the steam will be delivered to the Weyerhaeuser plywood factory as part of the cogeneration process.

The HRSG will have a natural gas fired duct burner to maintain the steam turbine electrical output during periods of high process steam flows to the plywood factory. (KG-13.3.) KG's application for an ACDP requested permission to use up to 1500 hours per year of duct burning. (KG-13.3.) KG and OE estimates of air emissions did not account for the emissions from duct burners. (KG-13.3.)

KG asserted that any extra emissions from duct burning would be offset by displaced emissions from the Weyerhaeuser boilers. (KG-12.22.) HPP makes that assertion as well for the Simplot boilers. (HPP-25.6.) We have no reason to believe that the same displacement would not occur for Weyerhaeuser boilers as for Simplot boilers. In addition, in both cases, the thermal efficiency of the proposed cogeneration processes will be much greater than the existing boilers, rendering any increases negligible. (KG-12.22; HPP-25.6.)

We find that any air emissions caused by short-term use of duct burning will be offset by displaced emissions from existing steam boilers.

7. Load factor

OE assumed the project load factor will be 100 percent, operating for 8,760 hours per year. (OE-11.27.) KG initially calculated emissions using a load factor of 85 percent. However, the project is proposed to be fully dispatchable, and KG would be allowed to operate at 100 percent load. (KG-13.2.) OE also assumed a 100 percent load factor for each of the other applicants in order to evaluate them on an even playing field. (OE-11.27-11.28.) The Council agrees that use of 100 percent load factor for calculation of power output, fuel use and emissions for the KG and other projects is reasonable.

8. Air Emissions

a. CO_2 emissions

KG proposes to use both natural gas and distillate oil as fuel. Each fuel has a different heat rate, requiring separate calculations to derive the total annual project fuel use and air emissions.

As noted above, we estimate that natural gas will be used for fuel for 8,400 hours per year. Based on the heat rate and energy output figures set out above, natural gas use will 18,144,000 MMBtu/yr. (OE-36.8.) The carbon rate for natural gas is 31.9 lb/MMBtu; the CO_2 rate is 116.97 lbs/MMBtu.

As noted above, we estimate that distillate oil will be used as fuel for 360 hours per year. Based on the heat rate and energy output figures set out above, annual distillate oil use will be

840,600 MMBtu/yr. (OE-36.8.) The carbon rate for distillate oil is 44 lb/MMBtu; the CO_2 rate is 161.33 lbs/MMBtu.

The total annual project emissions from both natural gas and distillate oil will be 1,129,033 tons/yr. (OE-36.8.) Over the 30 year life of the project, CO_2 emissions will total 33,870,979 tons. (OE-36.1.)

b. NO_x emissions

We calculate NO_x by using the values established above for nominal electric generating capacity, annual nominal power use, primary fuel use and secondary fuel use. The NO_x rate for natural gas for this energy facility is 0.00012 lb/Kwh. (OE-36.8.) The NO_x emission rate for distillate oil for this facility is 0.000366 lb/Kwh. (OE-36.8.) Annual Nox emissions for this facility are 171 ton/yr. (OE-36.8.) NO_x emissions over the 30 year life of the facility will total 5,137 tons. (OE-36.1.)

c. PM-10 particulate emissions

We calculate the PM-10 emissions using the values established above for nominal electric generating capacity, annual nominal power use, primary fuel use and secondary fuel use. The PM-10 emission rate for natural gas for this facility 0.0000254 lb/kwh. (OE-36.8.) The PM-10 emission rate for distillate oil for this facility is 0.000218 lb/Kwh. (OE-36.8.)

Annual PM-10 emissions for this facility will be 43.9 ton/yr. (OE-36.8.) However, the KG project will be located in the Klamath Basin, an air quality non-attainment area. KG will be required, as a condition of its ACDP, to offset particulate emissions by 35 tons/yr. (Tr. 264.)

PM-10 emissions will therefore total 8.9 ton/year. (OE-36.1.) Based on that annual output, total PM-10 emissions over the life of the project will be 266 tons. (OE-36.1.)

1. Purchase of PM-10 offsets

The Oregon Department of Environmental Quality (ODEQ) will require the project to reduce its PM-10 emissions by 35 tons per year as a condition of its Air Contaminant Discharge Permit. (KG Request, Table 1-1, page 1-3; Tr 261-262.) KG intends to purchase banked PM-10 offsets in the Klamath Falls area to offset 35 tons annually of PM-10.

UGC argues that KG should not be given credit for acquiring PM-10 offsets that are required by ODEQ. UGC argues that if KG uses banked emission credits, there would be no reduction from current PM-10 emissions in the Klamath Area. Second, UGC argues the PM-10 offsets required by ODEQ are a cost the KG project has incurred by selecting a site in or near a nonattainment area in order to have the same level of impact that would be allowed in an attainment area. Therefore, UGC states, there is no real reduction of PM-10 emissions as a result of the ODEQ requirement for PM-10 offsets. UGC estimates that calculating KG's PM-10 emissions based on actual emissions increases the net monetized value of air emissions for the KG project by about 0.02 mils/Kwh. (UGC-28.7-9.)

KG states purchase of banked emission credits is recognized in Oregon and is used extensively in other parts of the county. (Tr 264.) KG stated that by purchasing the offsets, it would prevent some other party from using them. In effect, purchased emissions displace other emissions or prevent other emissions from occurring. If offsets are not purchased within a set time, they become the property of the State. The State can then use them to offset emissions from activities not specifically required to obtain offsets. (Tr 269-270.) OE credits KG with the 35 tons per year offset in its baseline analysis of KG's plant performance. OE estimates the net PM-10 emissions at 8.9 tons per year. (OE-8.9.)

UGC argued that the PM-10 offsets were not "additional" and that KG should not be given credit for them. The requirement to purchase PM-10 offsets is essentially the same as a requirement to reduce emissions through direct emission control, therefore we take it into account in determining the "facility's emissions" under OAR 345-023-010(2)(b)(A), not as an offset under 010(2)(b)(C). However even if it were properly viewed as an offset under 010(2)(b)(C), we find the use of offset credits to be additional. The record shows that there is an established market for these offsets, and that if KG does not use them, they will be used by others. KG's purchase of the offset credit will therefore provide additional improvements in the air in the Klamath Basin.

The Council finds that use of banked emission credits for PM-10 is a recognized element of air quality control. UGC's argument that offsetting emissions is a cost of building in a nonattainment area is irrelevant. The rule does not differentiate the cost of PM-10 between attainment and nonattainment areas. We accept OE's analysis using the purchased PM-10 credit in the evaluation of plant performance.

C. Cogeneration Proposal

KG proposes to supply process steam from the electric generating facility to a Weyerhaeuser Co. plywood and particle board manufacturing facility. The steam will displace steam currently generated by boilers within the Weyerhaeuser facility.

1. The cogeneration agreement

a. Proof of a cogeneration contract

OAR 345-23-010(2)(b)(C) requires an applicant claiming credit for cogenerating to produce an agreement with the steam host. In its request, KG asserted its intent to cogenerate and described in general terms its agreement with Weyerhaeuser. (KG Request, Section 3.2). KG did not submit its contract with the request because it had unresolved concerns about confidential information in the agreement. (Cover letter to KG Request to Sam Sadler, ODOE, from Timothy E. Donnelly, Klamath Energy, Inc., February 29, 1996, page 2). Once the protocols for treatment of confidential information were in place, KG did submit a redacted version of the agreement.

As described above, KG moved to add the agreement to its request as a late-filed submission. OE argued that the hearing officer should accept the submission because the late submission was consistent with the descriptions in the request, and was justified by KG's confidentiality concern. The hearing officer denied KG's request to add the agreement to its request, but invited KG to introduce the agreement during the evidentiary stage of the hearing, which KG did.

Our intent in adopting OAR 345-23-010(2)(b)(C) was to require production of some form of contract with the proposed steam host. The rule does not, however, prescribe *when* the contract was required to be submitted. We believe, consistent with our policy on amendments, that later submittal of the contract was permissible under the rule. The request clearly stated KG's intent to claim a cogeneration offset and described the nature of the offset. The contract may properly be viewed as a clarification of that offset proposal.

Even if the rule were interpreted to require production of the agreement at the time of submittal of the request for exemption, we believe KG's concern about confidentiality justified late submission of the contract. We note also that no party has made a plausible claim of prejudice caused by the late submission. Whether the submission is viewed as a clarification of a proposal that was described in the request for exemption or as a late submittal, the agreement is properly part of the record in this proceeding, and we will consider it.

b. Proof of price information by submittal of affidavits

KG redacted pricing information from its agreement with Weyerhaeuser. It then submitted testimony that the price terms would create economic incentive for Weyerhaeuser to take KG steam for use in its wood processing facility.

The rule does not preclude use of means other than the agreement itself to prove some terms of the agreement. KG's submittals demonstrate that the agreement exists. (KG-32.8.) The testimony provides some additional information about the price terms. This type of demonstration is not precluded by the rule.

c. The nature of the cogeneration agreement

KG characterizes the contract as a "requirements type" contract, supplying whatever steam needs that the Weyerhaeuser plant has. HPP argued that the obligation is illusory since Weyerhaeuser is not bound to use KG as its exclusive source of steam. (HPP-32.41.) We agree with HPP that the KG-Weyerhaeuser agreement is not a true requirements contract because there is no obligation on Weyerhaeuser's part to satisfy its requirements from KG. Indeed, KG's witness Timothy Donnelly made this point asserting that KG "could not obligate Weyerhaeuser to purchase." (Tr 215-16.)

Unlike cases HPP cites, the steam obligation is only one part of a multi-faceted agreement that includes a binding option for a long term lease of property for the power plant.[4] Thus, mutuality of obligations exist. KG is obligated to provide steam as needed at a set price and to make payments regarding leased land at a set price for the duration of the project. Weyerhaeuser is obligated to lease the land. (See KG-Weyerhaeuser Agreement, KG-32.8.) The contract specifically identifies the land, the price and the duration -- the elements HPP insists must be part of a binding agreement. (HPP-32.42-44.)

But because Weyerhaeuser has no obligation to purchase any steam from KG, Weyerhaeuser is free to produce its own steam or purchase it from other sources. As UGC has argued, the steam provision of the contract is essentially an option, permitting Weyerhaeuser the option of purchasing steam at a set price as it desires.

KG offered evidence showing that Weyerhaeuser would have a financial incentive to purchase steam from KG, rather than rely on its own boilers. Although price information was redacted from the MOU because of concerns about confidentiality of proprietary information, KG witness Donnelly provided information about price terms that permits findings about the likelihood that the cogeneration will occur. We find, based on Donnelly's testimony and documents from Weyerhaeuser (KG-5.21 and KG-3.61.), that under the agreement, KG will provide steam to Weyerhaeuser at under 80 percent of Weyerhaeuser's current energy production cost. This

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[4]In each of the cases HPP cites, the illusory contract involved a single stand alone "promise" and was not part of a larger exchange of obligations. *See Heinzel v. Backstrom*, 310 Or 89, 96, 794 P2d 775 (1990); *Pacific Pines Constr. v. Young*, 257 Or 192, 196, 477 P2d 894 (1970); *Lemler v. Bord*, 80 Or 224, 227, 156 P 1034 (1916).

discount represents over $1,000,000 in annual energy savings to Weyerhaeuser. (Tr 233.)

UGC argues that the KG-Weyerhaeuser agreement may undercut KG's tax exempt status. (UGC-41.43.) UGC is apparently referring to an outputs test. (UGC-41.43-44.) Because the contract is not an outputs contract, as discussed above, the arrangement does not appear to violate the outputs test. In addition, the status of the tax exemption of the financing is only relevant to explain why the contract was drafted as a requirements-type contract.

Another issue that arose regarding this cogeneration agreement was that Weyerhaeuser is looking to sell the plant. We find that there has been no showing that this possibility should have an impact on our analysis. A buyer, like Weyerhaeuser, would have an option to purchase steam and nothing suggests that it would not have the same incentives as would Weyerhaeuser.

We recognize that the KG contract is not as specific as the HPP contract. When we adopted the requirement to provide a contractual agreement, we were looking for an expression of an intent of the applicant and the steam host to cogenerate. This agreement satisfies that intent.

2. Evaluation factors

a. Timing of the cogeneration offset

Under the KG-Weyerhaeuser agreement, KG is committed to generate steam for Weyerhaeuser's use. With this proposal, as with the HPP proposed cogeneration, cogeneration would take place concurrently with and as part of power generation.

b. Quantification of emissions displaced by cogeneration

i. Amount of steam to be supplied

KG estimates that the energy facility will deliver 199,800 lbs/hr of steam to Weyerhaeuser in the first year of commercial operation. (KG Request 3-4.) Because the Memorandum of Understanding (MOU) between KG and Weyerhaeuser indicates that 200,000 lbs/hr is the maximum amount of steam the host will take, OE staff assumed the project will not deliver more than that amount of steam. (Tr 356-357.) As discussed below, Weyerhaeuser has a significant economic incentive to use the steam provided by KG. We find that 200,000 lbs/hr annually is the appropriate figure for the amount of steam the facility will deliver to Weyerhaeuser.

ii. CO_2 displaced

Weyerhaeuser boilers currently use both gas and oil. KG estimates, based on the Weyerhaeuser PSEL's, that the boilers operate 87% of the time on natural gas and 12.2% on oil. (KG-3.8.) OE estimated annual fuel displaced by cogeneration at 2,431,776 MMBtu/yr. (OE-36.8.) Those figure were not disputed and we find them persuasive.

OE used a weighted carbon rate to reflect the use of both fuels. (OE-36.8.) Using a weighted carbon rate of 33.4 lb/MMBtu, annual CO_2 displaced will total 148,813 tons. (OE-36.8.) CO_2 displaced over the 30 year life of the project, without adjustment, will total 4,464,395 tons.(OE-36REV.3)

iii. NO_x displaced

Based on the weighted NO_x rate of 0.11 lb/MMBtu, the cogeneration process will displace 135 ton/yr of NO_x. (OE-36.8.) Over the thirty year life of the plant, a total of 4,048 tons of NO_x will be displaced, before adjustment. (OE-36REV.3).

iv. PM-10 displaced

Based on a weighted PM-10 rate of 0.00392 lb/MMBtu, the cogeneration process will offset 4.8 ton/yr. (OE-36.8.) Over the 30 year life of the facility, a total of 143 tons of PM-10 will be displaced, before adjustment.(OE-36REV.3)

c. Uncertainty

By comparison with HPP's proposed cogeneration project, KG's cogeneration proposal is fairly uncertain. First, the contract has no minimum take requirement binding Weyerhaeuser to take a specific amount of steam. Although KG provided testimony that it was in Weyerhauser's financial interest to purchase the steam, the pricing arrangements were not provided in the proceeding. This provides additional uncertainty as to whether, if circumstances changed, Weyerhaeuser would continue to have such an incentive. HPP also pointed out that the contract limits KG's remedies for a breach of the contract. Finally, the Weyerhaeuser plant is for sale, but the contract does not guarantee that acceptance of the contract would be a condition of the sale.

d. Monitoring/Verifiability

The amount of steam cogeneration, energy production displaced and net emissions saved is readily ascertainable and verifiable.

KG proposed a site certificate condition requiring it to report annually to the Council total and average pounds of steam delivered to Weyerhaeuser. The report will identify any modifications to the steam contract with Weyerhaeuser that will affect the quantity of steam being supplied.

We find that this proposed condition, together with other conditions attached to this order, is sufficient to verify whether the proposed cogeneration is taking place. It will also allow the Council to monitor the air emission benefits of KG's cogeneration.

3. Adjustment factor

Based on the foregoing, we conclude an adjustment factor of 0.5 is reasonable for this proposal.

4. Net cogeneration displacement

Application of the 0.5 adjustment factor to the gross CO_2 displaced by cogeneration yields net total displacement by cogeneration of 2,232,199 tons over the 30 year life of the project. (OE-36REV.1) Total displacement of NO_x by cogeneration, after adjustment, will be 2,025 tons. (OE-36REV.1) Total displacement of PM-10, after adjustment, will be 72 tons. (OE-36REV.1)

5. Monetized value of displaced emissions

Using the values set out in OAR 345-01-010(35), the monetized value of the net displaced emissions will be 0.33 mill/kWh. (OE-36REV.1)

D. Solar Rural Electrification

1. Proposal.

KG proposes to offset project CO2 emissions by funding the sale and distribution of household photovoltaic (PV) systems in India, China and Sri Lanka. The PV systems will provide electricity for lighting and small appliances, displacing CO_2 emissions created by current burning of fossil fuels (kerosene). KG proposes to commit $500,000 to a revolving investment fund (RIF) that will provide capital to one or more of three PV companies: the Solar Electric Light Company (SELCO) in India, Solanka Associates in Sri Lanka and Gansu PV Company (GPVCO) in China. (KG Request, 3-26 to 3-42.)

KG projected that the RIF would fund the installation of 182,000 PV systems over 30 years. KG assumed a reference case with baseline emissions of 367 tons of CO_2 per 1,000 households. (KG Request 3-33.) KG estimates total annual CO_2 benefit for each 1,000 PV systems at 360 tons. (KG Request 3-34.) KG states this will result in a cumulative CO_2 benefit of 2,360,000 tons over 70 years. (KG Request 3-35.) KG assumed a 30 year lifetime for the PV fund, and an effective life of each household system of 40 years including a one time replacement. (KG Request 3-34.)

2. Evaluation factors

a. Timing

i. Life of PV systems.

OE concluded the PV systems would each have a useful life of 20 years, rather than the weighted average of 38 years assumed by KG. (OE-11.19.) OE based this conclusion on the need to replace the solar panel of each system after 20 years, and the likelihood that other components of the system may need replacement on shorter intervals. (OE-11.20.) OE concluded that at year 20 an owner replacing a system would be no different than a consumer buying a new system. (OE-11.20, 11.9.)

KG disagreed, contending that it was reasonable to attribute replacement of a household's PV panel to subsidization of the original panel. (KG-31.18.) KG also asserted that crediting KG with the replacement of 80 percent of the PV panels at the end of their 20 year lives serves to counteract other substantial conservatisms in the KG analysis. (KG-31.18.)

Although it is likely the panels will be replaced at 20 years, they might be replaced anyway in the reference case. We find that a 20 year life is a reasonably conservative assumption and we adopt it.

ii. Life of the PV fund

OE originally assumed that the PV market will be fully commercial within 15 years. (OE-11.21.) OE assumed that PV systems installed after that time by KG would have been installed anyway, based on the assumption that PV firms will have access to capital at the same market interest rate offered by the fund after the PV market becomes mature in 15 years. OE assumed the cost of capital to PV firms from the KG fund will be 15 percent. (Tr 880.) For these reasons, OE recommended shortening the assumed lifetime of the PV fund from 30 to 15 years. (OE-11.21.)

KG asserts that OE's recommendation to shorten the lifetime of the fund is not reasonable. KG contends that the PV market will not be mature or saturated before 30 years. (KG-31.13.) KG also asserts that, because the cost of capital to the solar firms is zero percent, it represents a significant subsidy to the PV firms. (KG-31.14.) After reviewing the testimony provided by KG, OE concluded that it had misunderstood the proposal. (Tr. 880.) OE acknowledged that the fund would provide equity capital for up to 100 years at a zero percent interest rate, and that PV firms would not have to repay the capital they borrowed from KG's PV fund. (Tr. 880.) OE, however, declined to project savings past 30 years. Savings past that point are too speculative.

The Council agrees with the OE position and finds that a 30 year fund life is reasonable and supported by the evidence.

b. Quantification

i. Rate of return of the solar fund

HPP challenges the long term growth of the solar fund at the rate projected by KG, which is a commercial-level rate of return. (HPP-32.57 citing HPP-15.32-33, URP 1.4, Tr. 532.) HPP notes that the local SELF affiliates have only a one or two year history. (Tr 532.)

KG contends that its initial investment will grow at a 15% rate of return. In the application, KG states,

> "Financial analyses carried out by SELF have projected rates of return of 25 percent or higher. Using a conservative 15 percent estimated rate of return on the initial $500,000 offset investment, monies will become available for additional investment . . . ."

The hearing officer rejected the 15 percent rate on the ground that there is insufficient evidence in the record to support it. However, we believe the hearing officer has imposed an unnecessarily high evidentiary standard for proof of this particular estimate. The Council must determine by a preponderance of the evidence what number constitutes a reasonable forecast of a probable rate of return. Dr. Trexler testified to these rates of return based on his knowledge of the PV industry, the SELF projections and a World Bank report on Solar Photovoltaics. The value was unchallenged other than by veiled expressions of skepticism -- no facts were offered to refute it. (*See, e.g.,* HPP-15.32-33).

The record supports the forecasted 15 percent internal rate of return. Analysis of capital markets in developing countries indicates a 15 percent rate of return on the PV fund is reasonable. The publication *Solar Photovoltaics: Best practices for Household Electrification (1994)* from the Asia Alternative Energy Unit of the World Bank states that borrowing costs are 17 to 21 percent in India and Sri Lanka and 18 to 25 percent in China. (KG-31.15) Because early PV businesses are repaying loans at 17 to 25 percent, they must be earning at least this rate of return on their borrowed capital. Generally rates of return on equity capital are higher than on borrowed capital because equity capital faces greater risks. In this type of business environment a projected 15 percent rate of return on equity capital given to PV firms is not only reasonable, it is likely conservative. A further conservatism is to set the life of the PV fund at 30 years. If these businesses remain viable, they will likely install additional systems through year 100.

No party presented evidence to challenge these assertions. The financial analyses by SELF projected a rate of return of 25 percent or higher. (KG Request 3-34). SELF is a leading non-profit worldwide organization involved in promoting and financing PV systems in developing countries. (KG Request 3-27). No party offered testimony refuting SELF's projections.

The Council concludes that the 15 percent rate of return is reasonable for the purpose of calculating the benefit from this proposed offset.

ii. Other issues

Because much of the projected sales volume seems to be based upon credit sales, the question arises whether credit sales are a viable tool for the sale of these units. KG offered testimony showing that SELF or its affiliates have experience in credit sales. KG also offered testimony that SELF, affiliates or distributors would be able to enforce credit sales and reclaim units upon default. (KG-35.6-9.)

In short, KG demonstrated that it had, at least, developed a program that gave consideration to these concerns and developed a feasible approach that addressed these concerns. No evidence undercut KG's contentions that SELF and its affiliates would be able to implement the project as proposed, although numerous arguments were made. We are not persuaded by HPP's argument on this point.

HPP contends that, because the affiliated companies and organizations do not have lengthy business histories, the PV program does not demonstrate required institutional stability. (HPP-15.38.) KG replied was that the whole purpose of the PV fund is to help PV companies grow and become stable, and that working with more established companies would likely not produce additional CO_2 offsets. (KG-31.80.) We are persuaded by KG on this issue.

HPP questions whether the PV program should be credited with any amount of CO_2 offset. (HPP-15.42.) HPP questions the additionality, reference case, and project case of the PV program. HPP questions whether access to capital is the critical constraint for installation of PV systems. (HPP-15.31-34.) KG provided testimony and documentary evidence that the availability of working capital is the largest issue for developing rural PV markets. (KG-31.77, 31.79.) No party offered evidence discrediting KG's testimony on this subject, and the Council is persuaded by KG's testimony.

HPP asserts that KG has failed to clearly identify the reference case for evaluation of the PV program, arguing that it is unclear whether the PV program will displace kerosene lamps or grid-based power. (HPP-15.35-36.) KG responds by clarifying that the program was intended to displace kerosene lamps. (KG-31.78.)

HPP asserts that KG failed to adequately address the project case for its PV program. First, HPP contends that KG has failed to consider the energy used to manufacture PV systems. (HPP-15.34.) KG's rebuttal testimony contends that up-stream emissions from PV manufacture are likely either negligible or less than the standard error of quantifying the primary emissions benefits. (KG-31.78.) Moreover, KG maintains that including up-stream emissions associated with production of kerosene would increase the PV offsets by at least 10 percent. (KG-31.78.) We agree with KG and decline to take into account upstream emissions.

Second, HPP contends that it is uncertain whether households with PV's will discontinue use of kerosene lamps. (HPP-15.37.) KG's rebuttal suggests that kerosene lamps will be discarded in favor of PV lighting in part because kerosene lamps contribute to health problems and constitute a continuing fire hazard. (KG-31.80.)

Third, HPP argues that, if grid-based power does reach some of the PV households, those households will likely abandon PV systems. (HPP-15.38.) KG responds that extension of the electric power grid to rural areas is unlikely, due to infrastructure costs and power shortages. (KG-31.80.) KG also contends that use of PV systems will continue even with grid availability because of the increasing unreliability of grid-provided power. (KG-31.80.)

HPP also asserts that the fund relies on growth at commercial rates of return and ignores risk. HPP further asserts that if the project was so riskless and would generate the rate of return as proposed, then commercial investment funds would find their way into the projects. (HPP-32.56-57.) A similar argument was made by UGC that market and the demand already exists and that KG and SELF are doing nothing to develop this market beyond what would happen, in any event. (UGC-17.6.) KG responded by asserting that there existed other barriers to a successful implementation of such programs, including institutional, financial and educational barriers. (KG-31.78.) KG further contends that no other institution is providing this financing and their project overcomes this barrier. No party showed that financing was, in fact, being made available from other sources.

Fourth, HPP maintains that, based on existing deployment of PV systems, it is highly unlikely that the KG PV program will result in installation of the projected number of PV systems. (HPP-15.38-39.) KG testified that the number of PV systems proposed to be installed under the KG program was a fraction of the market, and that KG's projections were not unreasonable.

Fifth, HPP claims that host countries may not accept joint implementation of the KG PV program. (HPP-15.40-41.) KG states that the proposed host countries have shown increasing interest in joint implementation, and that, in any event, joint implementation is not a prerequisite for showing firm offsets. (KG-31.81-82.) We agree.

Finally, we note that UGC conceded that an additional 182,000 PV units could be sold in the time frame proposed in the countries targeted by the KG proposal. (UGC-17.2.)

We are not persuaded that these issues require us to deny credit for this offset. We have considered the issues that we believe create uncertainty in establishing the adjustment factor.

c. Uncertainty

OE found and we concur that there is a significant risk that the market for the PV systems would not be as favorable as anticipated. The project also faces risk from political upheavals in the subject countries. An additional uncertainty is whether households with access to these systems will in fact discontinue use of kerosene.

d. Monitoring/verifiability

KG's proposed monitoring and verification plan assures that project activities and outcomes can be adequately verified. PV companies will develop tracking databases of all units in circulation (operating systems) through their local and regional offices and through their technical support personnel at the village level. The PV companies and KG will also conduct periodic surveys (at five-year increments) of the usage patterns of households with systems, changes in kerosene consumption patterns, technology evolution, and other factors that could affect the CO_2 benefits of each unit. We find that this proposal allows us to verify that project measures are undertaken, and to monitor the performance of measure.

3. Adjustment factor

Based on all of the foregoing, we conclude an adjustment factor of 0.7 is reasonable.

4. Offset

Based on a projected gross offset of 1,340,475 tons (OE-36.15) and an adjustment factor of 0.7, we find that the total net offset for the KG PV proposal will be 938,332 tons of CO_2. (OE-36.1)

5. Monetized value

Multiplying the net CO_2 offset by the value in OAR 345-01-010(35) the PV emissions offset will have a net monetized value of 0.12 mills/kWh. (OE-36REV.1)

E. Methane Utilization

1. Proposal

KG proposes to offset facility CO_2 emissions by investing $1,000,000 in a revolving fund that will, in turn, invest in projects designed to utilize methane currently emitted from certain sewage treatment plants and coal mines. (KG Request 3-55.) The funded projects will capture and combust methane at each site, creating useable energy in the form of electricity. The projects will displace fossil fuel use and thereby reduce CO_2 emissions. (KG Request 3-55.)

KG proposes to invest $1,000,000 in a fund that will invest in methane utilization projects: $500,000 will go toward projects associated with sewage treatment plants; $500,000 will be directed to projects associated with coal mines. Each project will pay a rate of return back to the fund. (Tr 548.)

KG projects that the fund will have a lifetime of 30 years. (KG Request 3-63.) KG contends that the fund will lead to the installation of 30 MW of new generating capacity over that 30 year lifetime. (KG Request 3-63.) KG estimates CO_2 emissions will total 4.1 million tons over 100 years. (KG Request 3-63.)

The proposal is based on assumptions concerning the lifetime of the investment fund, the lifetime of the methane fueled generating equipment and the source and total of emissions offset.

2. Evaluation factors.

a. Timing.

i. Investment fund.

OE staff originally proposed that the methane investment fund should be credited with only ten years of offset benefits instead of the 30 years assumed by KG. (OE-11.22.) The reduction was based on OE's assumption that the methane fueled generation markets at both sewage treatment plants and coal mines will be fully mature and commercialized in ten years. (OE-11.23.) OE assumed that any projects funded after that time will not be "additional."

KG responded with testimony that clarified the nature of the revolving investment fund. (KG-31.20 to 31.30.) The testimony indicated that the fund was making zero interest equity loans; and returns to the fund were from net project revenues, not payments of interest. KG also provided evidence establishing the basis for its projected returns, revenues and operations of the fund based on experience at NW Fuels and detailed information about the market. (KG-31.22-23; KG-35.28-34.) KG also provided testimony supporting its assertion that the methane fueled generation markets will not be fully mature in ten years. (KG-31.24-25.)

OE revised its assumption and accepted KG's position that the fund should be credited with 30 years of offsets. (Tr 883.) OE concluded the fund will provide equity capital at a cost to the methane firms of 4 to 10 percent. (Tr 883.) OE also concluded that the assumed growth in the fund was reasonably conservative. (Tr 883.) Based on the evidence provided by KG, we concur with OE's conclusion.

ii. Lifetime of methane fueled generating equipment

KG assumes that the methane fueled generating systems will have a 60 year lifetime. (KG Request 3-60.) OE contended that 20 years is a more reasonable assumption. (OE-11.22.) OE based its opinion on the information provided in KG's proposal that the engines would require overhauling after two years of operation and would require replacement after four years of operation. (OE-11.22.) At this rate, five set of engines will be used by year twenty. OE staff concluded that the continued operation of the systems after year 20 would be attributable to ongoing maintenance and replacement of parts rather than to the initial investment. (OE-11.22.) We concur that a 20-year life is reasonable.

b. Quantification

i. Methane conversion

OE staff credited the KG project with 100 percent of the reduced emissions from displaced fossil fuel electric generation. (OE-11.24.) KG had subtracted the CO_2 emissions from the coal mine methane fueled generation. (KG Request 3-63.) OE based its credit on its finding that the CO_2 emissions from coal mine methane fueled generation would have occurred anyway when the coal mine methane emissions naturally degraded to CO_2. (OE-11.24.)

HPP argues that OE's credit results in an overestimate of the emissions reductions provided by the coal mine offset program. (HPP-27.12.) HPP asserts that OE is awarding credit to KG for offsetting methane and that methane is excluded from monetization by the Rule. (HPP-27.12.)

Based on OE's testimony, we conclude that KG erred in subtracting CO_2 emissions from the coal mine generating equipment. That CO_2 is also present in the reference case when current methane emissions naturally degrade to CO_2. Therefore we conclude it is appropriate to credit the KG project with 100 percent of the reduced emissions from displaced fossil fuel emissions

ii. Other arguments

HPP argued that the offset credits for KG's methane program should be substantially reduced. (HPP-15.48.) HPP raised questions concerning the fund, discounting, the reference case and the project case.

HPP asserts that the fund may have substantial expenses and overhead not accounted for in the proposal. (HPP-15.43.) HPP provides no factual basis for its assertion. KG responds that estimated costs were derived with the assistance of an expert in the field and are conservative estimates of anticipated administration and overhead expenses. (KG-31.83.)

HPP maintains that KG has failed to address the possibility of technological changes in the methane fueled generation field over the life of the project. (HPP-15.45.) HPP provides no evidence that such changes will occur or that they will affect the KG methane program. KG testified that technological changes had much less impact at the small scale of methane fueled generation. (KG-31.84.) KG also notes that EPA estimates of mine methane development indicate technological changes are not likely to affect the overall mine methane fueled generation development. (KG-31.84.)

HPP also argues that KG incorrectly assumed that the methane program will offset emissions from existing plants. HPP believes offsets should be calculated based on displacement of future energy production. HPP apparently contends, without any factual basis, that new facilities in coal mine areas will be based on significant technological advancements. (HPP-15.45-46.) KG testified that, due to the small size of the methane fueled generating units, they would not displace building of new energy facilities. (KG-31.84.) KG also asserted that it was appropriate to assume mine mouth generators will displace coal emissions because most electrical generation in coal mine areas is and will continue to be produced by coal. (KG-31.85.) We are persuaded by KG on this point.

HPP argues that the coalbed methane measure is based on the experience of a firm that has only one unit currently in service and a limited amount of operational experience. (HPP-32.57-58 citing Tr. 606.) While true, HPP offers no evidence that this technology is not effective there, is ineffective at other locations or somehow deficient. Indeed, KG offered testimony that it was effective where used, at two different locations. (Tr 554; KG-35.29-33.)

HPP also argues that the technology for the sewage treatment facility component of the methane measure is still being designed or adapted and there is no operational experience with it. (HPP-32.57-58 citing Tr. 554.) HPP's argument is partially true, but disregards Dr. Trexler's testimony that this technology is currently in place and is productive at both coalbed and larger treatment plants. Tr 552-54. Dr. Trexler explained that this existing technology can and will be adapted for use in the methane project. Tr 552-54. If there are reasons why this technology can not be adapted, HPP offers none. We are persuaded by KG on this point.

Finally, HPP contends that it is uncertain whether a coal mine will provide a steady supply of gas for the period claimed by KG. (HPP-15.47.) However, HPP provides no evidence to support its assertion. KG responds that EPA analysis uses an assumption of a 20-30 year supply of pipeline quality gas, and that it is reasonable to assume a supply of lower quality gas would continue for decades. (KG-31.85.)

We are not persuaded that the issues raised by HPP require us to deny any credit to KG. We have considered those issues that may create uncertainty in establishing the adjustment factor.

c. Uncertainty

It is possible that the fund may have substantial expenses and overhead not accounted for in the proposal, the technology in the methane fueled generation field may change over the life of the project, and there is uncertainty about whether coal mines will provide a steady supply of methane gas for the period claimed by KG.

d. Monitoring/Verification

KG's proposes a monitoring/verification plan in which the operator will monitor the volume of fuel consumed and the amount of electricity generated by the facility. CO_2 emissions from the project will be calculated directly from fuel consumption data, based on the known heat value and carbon content of methane. To determine the amount of CO_2 emission avoided from displaced utility fossil fuel generation, a CO_2 emissions factor for the utility will be calculated from the annual utility data on fuel consumption and net generation reported to the Federal Energy Regulatory Commission. If the serving utility has filed a 1605(b) report of its greenhouse gas emissions, this data will be used. KG will maintain accurate records on all project and utility data required to calculate CO_2 benefits, and will provide 1605(b) reports to the Council.

The Council finds that this proposed monitoring and reporting plan allows it to verify that the proposed measure will be undertaken, and to monitor the performance of the measure.

3. Adjustment factor

Based on the foregoing we conclude an adjustment factor of 0.6 is reasonable.

4. Offset

Based on our conclusions concerning the lifetime of the fund and of the generating equipment, we find that, before adjustment, the methane utilization program will offset 4,544,821 tons of CO_2 over the life of the project. (OE-36.15.) Of this total, 595,097 tons will result from the sewage treatment plant element and 3,949,724 tons will result from the coal mine element of the program. (OE-36.15.)

Based on a projected gross offset of 4,544,821 tons of CO_2 and an adjustment factor of 0.6, the total net offset for the KG methane program will be 2,726,892 tons. (OE-36REV.1) Of that total, the sewage treatment element will result in offset of 357,058 tons, and the coal mine element will result in offset of 2,369,834 tons. (OE-36REV.1)

5. Monetized value

The methane program will result in emission offsets with a total monetized value of 0.33 mils/kWh. Of that total, 0.04 mils/kWh result from the sewage treatment element, and 0.29 mils/kWh result from the coal mine element. (OE-36REV.1)

F. Geothermal Heating

1. Proposal

KG proposes to offset project CO_2 emissions by enhancing the geothermal central heating system of the city of Klamath Falls. The project will provide a revolving credit fund to facilitate the hookup of space heating systems in downtown buildings to the existing geothermal heating system. (KG Request 3-69.)

The project will establish a $100,000 revolving fund to assist in the hookup of additional buildings. KG estimates that over 30 years 140 additional buildings will be connected to the geothermal heating system. KG estimates CO_2 savings of 7.31 tons per year. CO_2 benefits for the entire project lifetime will total 614,440 tons. (KG Request 3-69.)

The estimated offsets are based on assumptions about the additionality of new hookups over the lifetime of the fund.

2. Evaluation factors

a. Timing

KG assumed the revolving fund will fund hookups for thirty years and each building hookup will be credited to KG's program for 60 years. OE recommended reducing the credit to thirty years, contending that after thirty years those systems would have been in place without the fund. (OE-11.25.) OE recommended reducing the installation term to 15 years to account for hookup of systems that will occur even without the fund. (OE-11.25.)

In light of a lack of reliable evidence about the demand for geothermal hookups in the future, we are unable to credit KG for the life of the fund and usefulness of the hookups to the degree it claims. We adopt OE's approach based on its familiarity and expertise with energy conservation funds.

b. Quantification

KG maintained that even though the geothermal heating system has been in existence for years, few buildings have been connected, due primarily to the low price of natural gas. (KG-31.31.) KG argued that natural gas prices are predicted to stay low. Therefore, KG believes the fund will support additional hookups for thirty years, and all buildings hooked up by the fund should be credited as additional for the full 60 years. (KG-31.31.)

KG's witness Trexler, however, testified that four or five buildings were hooked up to the system in each of 1994 and 1995. (Tr 536.) KG's predictions result in an average of 4 2/3 hook-ups each year its plan fund is in effect. That is the same hook-up rate that the program is currently experiencing without the program. This recent activity suggests that building owners are motivated to hook-up to the geothermal heating system without low interest loans provided by the fund.

If we were to consider only the last two years activities, we would likely conclude that there is no basis on which to conclude that low interest loans from KG's fund would cause any additional hook-ups and displacement of CO_2 emissions. However, we are compelled to consider all the evidence in the record, including the prior 15 years where there were no additional hook-ups.

Because there was no showing that hookups over the last two years are based on any fundamental change in the market incentives, we must consider these hookups to be an aberration. We therefore infer that the incentive created by the geothermal fund would likely generate new, additional hookups that would not otherwise be made. We therefore find that the hookups generated by the funding program would be additional.

c. Uncertainty

Unlike the methane fund's reliance on a private firm, this proposal is backed by the City of Klamath Falls, giving it greater security. Nevertheless there is still some uncertainty that the city will not be able to install the projected number of geothermal systems.

d. Monitoring/Verification

The number of installations proposed is small and easily verifiable through regular reporting. KG proposes to report all CO_2 benefits associated with the project to U.S. DOE under Section 1605(b) and will provide copies of the reports to the Council.

3. Adjustment factor

Based on the foregoing we assign an adjustment factor of 0.9 to this proposal.

4. Offset

Based on conclusions we make above, the gross emissions offset from the geothermal program amounts to 157,104 tons of CO_2.

Based on the estimated gross CO_2 offset of 157,104 tons and an adjustment factor of 0.9, the total net offset for the KG geothermal fund will be 141,393 tons of CO_2. (OE-36REV.1)

5. Monetized value

Based on the $10/ value of CO_2 set out in our rule, we estimate the KG geothermal program will result in emission offsets with a total monetized value of 0.02 mils/kWh. (OE-36REV.1)

G. Forest Resources Trust

1. Proposal

KG proposes to increase carbon sequestration by contributing $1,500,000 to the Oregon Forest Resource Trust (FRT). The 1993 Oregon Legislature established the FRT as a long-term revolving loan fund, administered by the Oregon Department of Forestry (ODF), to assist in reforestation of private nonindustrial forest lands. The Legislature designed the FRT to be self-supporting after an initial infusion of funds. However, the Legislature withdrew funding from the FRT in 1995 before it could become self-supporting. As a result, fewer than 1,000 acres will be reforested with available funding. (KG Request 3-44.) KG projects that the infusion of its funds will enable the FRT to generate substantial matching funds that will result in additional reforestation, sequester carbon and create other benefits. (KG Request 3-43.)

KG asserts that its contribution of $1,500,000 into the Trust will generate matching funds of an additional $4,500,000. These funds will be sufficient to reforest almost 11,000 acres in western Oregon, creating a CO_2 benefit of 7,400,000 tons in 65 years. (KG Request 3-44.) The proposal includes important assumptions about the likelihood of matching funds, the amount of acreage that will be reforested, and about the baseline case and the project case. KG assumes the FRT will plant 25 percent of the trees on cropland (Site Class II) and 75 percent on pasture (Site Class III). Under this scenario, KG estimates the carbon sequestration will be 669 tons of CO_2 per acre after 65 years. KG’s primary source of data was Birdsey. (Application, Table 3-3, 3-23; 3-43, 3-44, 3-47, 3-48.)

2. Evaluation factors

a. Timing

i. Length of cycle.

KG based its estimate of carbon offsets from its contribution to the FRT program on a 65 year analysis. KG revised its estimate to a 100 year analysis, as requested by OE. (KG-13.9-10.) OE's original estimates terminated analysis after at year 65, assuming that the average age of the stand after 65 years remains at 65 years. (OE-14.1; OE-17.9.)[5] OE analyzed all offset proposals at 100 years.

HPP argued that there was no guarantee the land would not be harvested before that time. (HPP-15.54.) Figuring the harvest at year 65 is an accounting convention that reflects the assumption that harvest will occur on average at 65 years. OE argues that calculating the harvest for the average year is a reasonable approximation of the harvest cycle for this proceeding. (Tr 981.) We concur with OE's reasoning and find that projecting harvest at 65 years is supported by the evidence and is reasonable.

ii. Replanting and doubling of acreage at year 65.

Initially, OE terminated calculations at year 65. KG presented testimony that the curtailment of analysis at year 65 was not appropriate, for a number of reasons. (KG-31.40-42.) KG explained that each acre harvested would be replanted under the Oregon Forest Practices Act and that revenues returned to the FRT after harvest of the original acres at year 65 would be used to reforest an equal number of acres in addition to the reforestation of the original acres. (KG-31.42.) OE accepted this argument and revised its analysis.

Under its revised analysis, OE assumed that harvest will occur at year 65, and it revised its analysis of carbon sequestration through year 100. (OE-37.1; Tr 973.) OE assumed that after harvest, the original 6,250 acres would be replanted on Site Class II soils and an additional 6,250 acres would be planted on Site Class II and III soils after harvest at year 65. (OE-37.1-4; Tr 944-945, 976.) KG further contended and OE assumed that, upon harvest, both the original land and an equal number of additional acres would be reforested. (Tr 943-44.)

The Council concludes that the original land will be replanted after harvest and that an equal number of additional acres will be reforested. We recognize that the extension of offset credits beyond the first harvest involves some uncertainty. That uncertainty is included in the adjustment factor we apply to the FRT program.

[5] Initially, OE assumed that additional carbon sequestration acquired through replanting is offset by carbon consumed by fossil fuels during harvesting. KG later showed that this assumption was not empirically justified by calculations, and OE revised its carbon offset calculations. (KG-31.41.)

b. Quantification of offset

The projected offset depends on several factors: funding level, additionality concerns, cost of land and type of land planted and the growth and harvest cycle, replanting assumptions, soil carbon assumptions and species planted.

i. Funding level

. KG proposed to contribute $1.5 million to the Forest Resource Trust program. But KG calculates the carbon offsets that will result from its contribution to the FRT on the assumption that its contribution will prompt matching contributions on $4.5 million for a total of $6.0 million. (KG Request 3-43.)

KG presented additional evidence that its contribution to the FRT will prompt matching contributions. (KG-31.51-52.) Evidence included a letter from Mater Engineering, fund raising consultants to the Oregon Department of Forestry (ODF) (KG-31.105-06.), and a letter from the ODF stating that a one-to-one match of funds for KG's contribution to the FRT was reasonable and likely to be successful. (KG-31.107.) KG also stated that it was willing to guarantee raising an amount equal to the funds it contributed.

HPP claims KG’s use of matching funds introduces uncertainty into the calculations of benefits. (HPP-15.57-58.) These uncertainties are, however, overcome by the evidence presented by KG.

Based on the evidence from the ODF and its consultants, the Council concludes that a 1:1 match is reasonably likely. This conclusion is not based on the assurance by KG that it will commit to assuring the 1:1 match.

Any amount beyond the 1:1 match is too speculative to credit to KG, especially where there is no track record of raising such large amounts for the FRT.

ii. Additionality

Other applicants have argued that the land reforested with matching funds would not be additional and should not credited to KG. KG has responded by asserting that they will ensure that "the matching funds program it has discussed with ODF will not target contributors with an interest in carbon offsets." (KG 31.45.) In addition, landowners would be required to turn over carbon sequestration credits to ODF as part of their agreement with ODF. (Tr 613.)

iii. Acreage reforested

KG's estimates of the offset benefits from its FRT contribution assumes reforestation of 11,000 acres of land. (KG Request 3-43.) That assumption relies on $6 million being available to the FRT, based on a three-to-one match of funds, and an average planting cost of $550 per acre. (KG-31.48.) KG argues that a loss in matching funds will not result in a proportional reduction in offset tons because the FRT can target more productive acres if less money is available. (KG-31.1, KG-31.48.)

KG testified that an average cost of $400 per acre is the appropriate cost for the acres FRT would target with only a 1:1 match. (KG-31.49.) KG presented evidence from ODF that Site Class II sites will be available at this funding level. KG and ODF will agree to use the funds only for Site II lands in an MOU. (KG-31.50; KG-31.107.)

After OE revised its conclusion to assume a one-to-one match of funds, it also revised its estimated of acreage that will be planted, to 6,250 acres, based on an average cost $480 per acre. (OE-37.2.) OE adjusted the estimate of $400 per acre to $480 to account for inflation at 3 percent to the date the project would begin in six years. (Tr 975.)

KG argues that adding in an inflation factor is unrealistic since the funds will be in an interest-bearing account by 1997 and that ODF does not expect planting costs to inflate before then. (KG-37.84.) The Council can not, however, rely on the investment into the interest-bearing account, for there is no assurance that KG will even have completed the site certificate process by 1997. A prudent adjustment for 3 percent inflation rate is appropriate.

iv. Carbon sequestration calculations

KG's calculations of carbon sequestration relied on assumptions and data from the work of Dr. R.A. Birdsey. (KG Request 3-48). OE's experts, Drs. Vinson and Kolchugina, created their own model to evaluate both the KG and UGC forest carbon sequestration proposals.

The hearing officer rejected OE's estimates, based on his perception that it was inappropriate for OE to evaluate the FRT program by using data and assumptions from several different sources. (HO-15.61) The hearing officer also appears to accord a presumption of correctness to the Birdsey data and assumptions. He would require OE not only to present reliable data, but also to show that the Birdsey data was not reliable. (HO-15.61 nt.12) That is incorrect.

Drs. Vinson and Kolchugina's numbers were specifically designed to reflect local conditions. (OE-11.16; OE-14.1-1, Tables 1 & 2) In contrast, the Birdsey data are only a general representation of carbon in U.S. forests by region. In fact, Dr. Birdsey states in his unpublished manuscript:

> The methodology and data developed here can also be used to analyze the effects of specific actions outside the context of economic or policy models.
> * * * **<u>These methods should be reviewed or revised to be consistent with the scope and objectives of each analysis project.</u>** (Emphasis added). Data in the tables are the product of a complex set of assumptions that can vary with the interpretation of the studies on which they are based or by the use of other studies or analyses that are perhaps equally valid * * *. **<u>The assumptions should always be reviewed and accepted or rejected for each use of the data</u>.**

(Emphasis added) (KG-15.11).

OE's analysis of the forestry proposals was conducted by highly qualified experts who thoroughly documented the sources of the data and assumptions they used. OE also attempted, where reasonable, to use the same assumptions for each applicant in order to provide a level playing field for evaluation of the forestry programs. (Tr 958, 992, 994) Based on Dr. Vinson's testimony, his availability for cross examination, and the local sensitivity of his data, we find that OE's estimates of forest carbon sequestration are supported by a preponderance of the evidence.

a. Carbon losses at harvest

The record shows disagreement about the carbon impacts of harvest at year sixty-five. KG relied on Birdsey's general forest carbon data for its estimate of harvest impacts. OE used data from the UGC STANDCARB forest carbon sequestration model. (Tr 992-994) The STANDCARB data concerning harvest and post-harvest storage in wood products are specific to Oregon and Washington and are based on an assessment by Dr. M. Harmon, a Professor of Forest Science at Oregon State University, and a leading forest carbon dynamics expert in the Pacific Northwest. (Tr 992-994, OE 37.1).

Based on Dr. Harmon's STANDCARB data, Dr. Vinson assumed that 35% of the total forest carbon would be sequestered in long-term wood products after harvest, and 65% would be released into the atmosphere. (Tr 991-994) He further assumed the carbon stored in wood products would decay at a rate of 1.5% per year. (Tr 993). We find the STANDCARD data and assumptions developed by Dr. Harmon and used by Dr. Vinson accurately reflect the conditions in Oregon, and we adopt their use.

b. Net merchantable timber volumes

OE's estimate of carbon benefits included a reduction to compensate for the difference between gross and net merchantable timber volumes. (OE-11.18). KG presented testimony that some merchantable timber losses do not result in loss of carbon, as OE had apparently assumed. (KG-31, 36-37). OE revised its analysis and added 8.5 percent to the project case CO_2 pool to compensate for the difference between gross and merchantable timber volume. (OE-37.1-2). We find this adjustment to be appropriate.

c. Soil carbon

UGC had argued that OE should use zero for soil carbon because the dynamics of soil carbon are unclear. (UGC-20.2). KG argued that UGC's assumption that all carbon disappears at harvest in year 65 is not supported by the record. (KG-31.86). KG offered rebuttal testimony to support its position that the figures KG relied on showing increased soil carbon are justified and reflect plausible assumptions about the accumulation of soil carbon in the region. (KG-31.37). To be consistent in its analysis of KG and UGC forestry proposals, OE based its analysis of soil carbon accumulation on the figure proposed by UGC for both analyses. (TR 954-956, 990). Based on its calculation of what UGC used, OE assumes that soil carbon will accumulate at the rate of 0.0716 mt/ac/yr with first rotation growth. (OE-37.1). We find ODOE's reasoning on this point is appropriate. We assume carbon accumulation at the rate of 0.0716.

v. Leakage: Failure to account for changes in the marketplace

HPP argues that the other applicants and OE failed to analyze the market response to a wood product sink used as carbon storage:

> "there is no explanation or economic rationale in the record, for either the PFT or the FRT project, for how consumer response is changed to actually raise the

> demand for the timber that increases the size of the wood product carbon sink in the first place. (See, e.g., HPP-15.60, 15.69, 15.70, 27.16, 27.17, URP-1.5.)"

HPP-32.60. Any change in consumer response due to the KG's proposal, or the PFT proposal of the UGC, is too small to measure and, for the purposes of this proceeding is merely theoretical. While the accumulation of many such proposals over the long haul could have an impact, we need not concern ourselves about that in this proceeding.

vi. Species

In its application, KG proposed to plant native species, such as Douglas fir, western red cedar, hemlock, ponderosa pine, and incense cedar. (KG Request 3-46.) However, KG analyzed carbon sequestration from planting only Douglas fir. HPP stated that KG proposes to plant a mix of native species, not just Douglas fir. Therefore, they argued, assuming that all trees would be Douglas fir would overestimate the benefits of the KG proposal. (HPP-15.56; HPP-27.10.) KG subsequently clarified its Request and stated that it intends to plant only Douglas fir. (KG-31.87.)

c. Uncertainty

In comparison to the UGC forest proposal, we conclude that KG's forest proposal is less certain. KG's proposal is to spend certain amount of money to fund the FRT which will result in acreage to be replanted. However, unlike UGC, KG did not guarantee sequestration of a particular amount of CO_2. In addition, KG proposes to plant a single tree species that may be more vulnerable to disease and climate changes than a mix of species.

d. Verifiability

KG will report to the Council on parcels planted each year, including location, site class and numbers of trees per acre. Site inspections will take place on a yearly basis through year five. Silvicultural treatments may be adjusted based on these inspections. Additional seedlings may be planted as necessary to ensure the target number of trees per acre. KG will keep accurate reports by parcel of planting and follow-up treatments. KG will report CO_2 benefits associated with the project to the U.S. DOE under Section 1605(b) and will send these reports to the Council.

HPP argues that there is substantial uncertainty or unreliability as to carbon offset measures and points to wide range of opinions expressed by various parties and expert witnesses testifying in the field. HPP-32.50-52. HPP emphasizes as to forest-based carbon sequestration programs that "Dr. [Sandra] Brown testified that the on-site benefits of the project could be demonstrated through monitoring and verification only to a certainty level of plus or minus 50 percent. (Tr. 785, 786, 789, 790.)" HPP-32.51-52. Significantly, no witness disputed either Dr. Brown's testimony or her estimate of the error range. Her testimony stands unrebutted and credible based on her background as provided in direct testimony. HPP-20.1-4.

KG argued that the testimony of Dr. Brown addresses only the subject of monitoring and verifying the carbon benefits of the PFT project and does not apply to KG' s FRT. KG observed that they are very different projects, with the PFT project being vastly more difficult to monitor than the FRT and that even HPP's witness Richards noted that the FRT could "be monitored within the bounds indicated by Dr. Brown.” Tr. 841, ll.2-3. Richard's comments, however, do not address Dr. Brown's concerns about estimating forest biomass and, concomitantly, the offsets attributed to that forest biomass.

On the other hand, Dr. Brown's concerns do not undermine determinations here regarding quantity of estimated carbon sequestered in forestry projects. To account for Dr. Brown's undisputed error range, we would have to know more about the confidence level she envisioned when mentioning the error range of plus or minus 50 per cent. Dr. Brown's testimony does not discredit or rebut Dr. Trexler's or OE's estimates, using the Birdsey and STANDCARB dataset.

The Council finds that these proposed measures will allow it to verify that KG actually undertakes the FRT measure it proposes and to monitor the performance of the FRT measure.

3. Adjustment factor

Based on the foregoing, we find the KG FRT proposal is substantially certain. We find that an adjustment factor of 0.8 is reasonable representation.

4. Offset

KG estimates that carbon benefits will be 1035 tons of CO_2 per acre based on revised assumptions concerning a 1:1 match based on replanting, planting a second field and accrual of benefits to year 100. (KG-31.53.) OE estimated gross carbon offsets applying these same assumptions but using different values for carbon losses at harvest, net merchantable timber, volumes and soil carbon. As we discussed earlier, we are persuaded that OE's values on these parameters are better estimates. (OE-37.1-4.) Accordingly, we find the KG FRT contribution will result in a carbon offset of 4,190,000 tons, before adjustment. (OE-36REV.3) Applying the 0.8 adjustment factor to the gross estimated carbon offset results in a net CO_2 offset of 3,352,000 tons. (OE-36REV.1)

5. Monetized value

Based on the carbon value of $10/ton set out in OAR 345-01-010(35), we find the net monetized value of the FRT offset is 0.41 mils/kWh. (OE-36REV.1)

SUMMARY

Net Monetized Value of the KG Offset Proposal.

As set out above, we estimate that the gross emissions from the KG energy facility will be 33,870,979 tons of CO_2, 5,137 tons of NO_x and 266 tons of PM-10 particulates. The monetized value is 4.31 mills/kWh.

The adjusted value of emission offsets are as follows:

In tons	CO_2	NO_x	PM-10
Cogeneration	2,232,199	2025	72
Forest Resources Trust	3,352,000		
Solar electrification	938,332		
Sewage methane	357,058		
Coal mine methane	2,369,834		

In tons	CO_2	NO_x	PM-10
Geothermal	141,393		

The monetized value of these emissions per kWh of output is 0.33 mils for cogeneration, 0.41 mills for the reforestation program, 0.12 for the solar electrification program, 0.04 for the sewage methane program, 0.29 for the coal methane program and 0.02 for the geothermal program. All offsets taken together have a monetized value of 1.21 mills/kWh.

The monetized net emissions (from output minus offsets) is 3.10 mils/kWh.

VII. FINDINGS OF FACT: UMATILLA GENERATING COMPANY

A. Proposal Configuration

Umatilla Generating Company proposes an electrical generating facility consisting of two essentially identical side-by-side combustion turbines, two heat recovery steam generators (HRSG), and two steam turbines. (UGC Application B-1.)[6] The energy facility will have a nominal electric generating capacity of 500,000 kw. (UGC Request 4.)[7] The facility is intended to be fully dispatchable and may therefore operate for 8,760 hours per year. (UGC-7.3.)

The primary fuel for the facility will be natural gas. (UGC Application B-1.) A secondary fuel will not be used. (UGC-7.5.)

The Request includes two alternative proposals to offset CO2. Alternative A has two components. Under the first component, UGC will replace 1,100 wood stoves in Oregon with certified wood stoves, pellet stoves, and/or gas heaters. (UGC Request 25.) The second component will require UGC to offset 561,500 tons ofCO_2 through acquisition of forest land easements under the Pacific Forest Trust (PFT) program for carbon sequestration. (UGC Request 25.) Under Alternative B, UGC will offset 1,123,000 tons of CO_2 through acquisition of forest land easements under the PFT program for carbon sequestration. (UGC Request 27.)

[6]The "UGC Application" refers to the Application for Site Certificate.

[7]The "UGC Request" refers to the Request for Exemption.

B. Turbine Availability

Estimates of the UGC facility operating capacity, fuel input, power output and air emissions were based on UGC's use of the General Electric (GE) 7H combustion turbine. (UGC Application 5.) The 7H turbine will use advanced technological and design features not used in any commercially operating turbine. However, the turbine has been commercially offered by GE. (Tr 281.) UGC expects the 7H technology to be commercially available within two years of issuance of the site certificate, when construction is expected to commence. (UGC Request 5; Tr.80, 155.)

HPP asserted it was unlikely the GE 7H turbine would be available for use in the UGC facility as proposed. (HPP-17.14; HPP-19.2-19.4.) Based on that uncertainty, HPP argued the heat rate for UGC should be based on the heat rate of the manufacturer's most efficient commercially operating machine. (HPP-19.7.)

HPP claimed that the 7H technology is not currently available in commercial operation, and has never been tested in operation. (HPP-17.1-17.6.) HPP claimed that development of the 7H turbine presents significant design challenges and will require solving difficult technological problems, particularly involving the increased combustion temperatures and steam cooling system. (HPP-17.5-17.7.) HPP also raised questions about the uncertainty of continued funding for development of the 7H turbine. (Tr 279-81, 284-88.)

In its evaluation of all of the proposed projects OE used the information supplied by the turbine manufacturers to determine the heat rate. All of the manufacturers are established and reliable providers of combustion turbines; their professional and commercial reputations depend on meeting equipment performance specifications and representations. (Tr 311.) OE assumed that the proposed technologies would be commercially available.

HPP's testimony identified uncertainties in the turbine design and construction. UGC presented evidence supporting its position that the turbine will be available and will perform as specified.

UGC testified that it will be able to put the GE 7H turbine in commercial operation at the proposed project site within three-and-a half to four-and-a-half years from July, 1995. (Tr 81.) UGC presented testimony that the technology was practicable, and that the design and technological issues have been substantially resolved. (UGC-27.15-16.) UGC presented testimony that the General Electric Company has made a commercial commitment to provide the technology (UGC-27.12.), and the manufacturer is prepared to move forward with the manufacture, installation and operation of the turbine. (Tr 309.)

Based on the testimony presented by UGC and the evidence in the record, the Council finds that the GE 7H turbine will be commercially available for use in the UGC project in the time frame projected.

C. Generating Capacity

1. Nominal power

UGC used various estimates of the nominal power of its proposed facility. (UGC Request 6; UGC-7.1.) UGC indicated in its proposal that it desired a site certificate condition limiting the facility to nominal electric generating capacity of 500,000 kW. (UGC Request 4.) OE evaluated the project based on a nominal generating capacity of 500,000 kW. (OE-36.8.) The Council finds that the 500,000 kW nominal electric generating capacity is a conservative figure for evaluating the UGC facility because it is the maximum output and represents the highest total emissions. The Council adopts that figure.

2. Annual energy output

As discussed above, the nominal electric generating capacity of the project will be 500,000 kW. Based on a 100 percent load factor (8,760 hours per year), we find that the annual nominal energy produced will be 4,380,000,000 kWh. (OE-36REV.8-9.)

3. Heat rate

UGC's Request states that the combined cycle GE 7H turbine will have a fuel chargeable to power heat rate (primary heat rate) of 6,500 Btu/kWh. (UGC Request 8.) OE derived a similar rate by extrapolation from the total annual electric production and total annual fuel input figures provided by UGC. (OE-12.8.)

HPP asserted that there is uncertainty about whether the turbine will meet the declared heat rate and emissions rates, because the GE 7H turbine relies upon unproven and untested technological developments. (HPP-19.6-7.)

UGC presented testimony that it is confident the 7H turbine will meet the declared heat rate. (UGC-27.13; Tr 291.) The testimony indicated that the net plant heat rate advertised by the manufacturer was 6,398 to 6,409 Btu/kWh HHV. (UGC-27.13.) The heat rate proposed by UGC, 6,500 Btu/kWh, was more conservative than the heat rate proposed by the turbine manufacturer.

HPP also asserted that, due to the higher combustion temperatures and the steam cooling system proposed for the GE 7H turbine, there was a greater likelihood that the heat rate would degrade significantly over time. (HPP-17.7-17.8.)

UGC presented expert testimony that the degradation of the 7H turbine over time will not be greater than the other turbines. (Tr 297-300.) UGC asserted that the degradation issue raised by HPP was primarily a parts life issue and that GE had incorporated design features to limit that problem. (Tr 299-300.) UGC also testified that heat rate degradation varies according to maintenance and site conditions. (Tr 328.) UGC testified that there was no reason to believe that heat rate degradation due to maintenance and site conditions would be different for the GE 7H machine as compared to other GE machines. (Tr 328.) HPP did not provide evidence on those factors.

Based upon the foregoing, the Council finds that the GE 7H turbines will meet the declared heat rate and that the 7H heat rate will not degrade significantly more than the other proposals over time. The use of 6,500 Btu/kWh as the heat rate for the UGC proposal is reasonable.

D. Air Emissions from Power Generation

1. CO_2 Emissions

Using a natural gas carbon rate of 31.9 lb/MMBtu, and a CO_2 rate of 116.97 lbs/MMBtu, the annual project CO_2 emissions will total 1,665,002 ton/yr. (OE-36REV.8-9.) Over the 30 year life of the project, CO_2 emissions will total 49,950,063 tons. (OE-36.2.)

UGC does not propose to use duct burning at its facility. (UGC-7.5.)

2. NO_x emissions

NO_x emissions are calculated by using the values established above for nominal electric generating capacity, annual nominal power use and primary fuel use. The applicant estimated a maximum NO_x rate for the STAG 107H turbine at 235 lb/hr. (UGC-7 (attachment)). OE staff converted the rate to express NO_x emissions in lbs/kWh, yielding a rate of 0.00011 lb/kWh. (OE-36REV.8-9.)

Based upon annual energy production of 4,380,000,000 kWh, annual NO_x emissions will be 241 tons per year. (OE-36.8.) NO_x emissions over the 30 year life of the project will total 7,231 tons. (OE-36.2.)

3. PM-10 particulate emissions

PM-10 emissions are calculated by using the values established for nominal electric generating capacity, annual nominal power use and primary fuel use. The applicant estimated the PM-10 rate for the STAG 107H turbine at 15 pounds per hour. (UGC-7 (attachment)). OE staff converted the rate to express emissions in lbs/kWh, yielding a rate of 0.0000382 lbs/kWh. Based on annual energy production of 4,380,000,000 kWh, annual PM-10 emissions will be 83.6 ton/yr. (OE-36.8.) PM-10 emissions over the 30 year life of the project will total 2,507 tons. (OE-36.2.) We concur with OE's estimate.

4. Monetized gross emissions

We multiply each of the values of these emissions calculated above by the amount provided in OAR 345-01-010(35.). Based on those calculations, the monetized value of the gross air emissions from the UGC facility is 3.95 mil/kWh.

E. Offset Proposals

UGC proposes two alternative emission offset programs. Alternative A has two components: replacement of 1,100 uncertified wood stoves; and, guaranteed offsets of 561,500 tons of CO2 at 100 years through through acquisition of about 1,000 acres of forest land conservation easements for carbon sequestration. Alternative B has a single component: guaranteed offsets of 1,123,000 tons of CO_2 at 100 years through through the acquisition of about 2,000 acres of forest land conservation easements for carbon sequestration. UGC will implement whichever alternative the Council prefers. (UGC Request, 25-28.) The alternatives are discussed below.

F. Wood Stove Replacement

1. Proposal

UGC proposes to offset CO_2 and PM-10 emissions by replacing 1,100 existing wood stoves in Oregon with 400 certified wood stoves, 300 pellet stoves, and 400 gas stoves. UGC will work with the Oregon Department of Environmental Quality to identify areas for the program and potential lower income participants. (UGC

Request 12, 19, 25; UGC-28.5.) UGC commits to replacing the 1,100 uncertified wood stoves under Alternative A. (UGC Request 12, 19, 25.) The replacement stoves will be cleaner burning, more efficient or both, resulting in a net reduction in air emissions. The proposal is based on assumptions about the heating value of wood, the mix of replacement wood stoves, net CO_2 emissions, and PM-10 emissions from uncertified wood stoves in the base case.

2. Evaluation factors

a. Timing

UGC plans to run the program replacing the stoves over a five year period following commencement of operations. (UGC Request 22.) Given that UGC plans to replace only 1100 wood stoves (UGC Request 13.), UGC is likely to meet this time line. The program is occurring in a time frame both easy to verify and likely to occur.

b. Quantification

i. CO_2 offset.

UGC claims a reduction of CO_2 of 4,096 tons per year from its wood stove substitution program. It claims the reductions as a result of improved efficiencies, thermal efficiencies, or reduced carbon in natural gas. It also acknowledges that there is no additional CO_2 from burning wood when trees are replanted. (UGC Request 19-21: C-1-C-4.)

KG argues that improving the efficiency of a net zero CO_2-content fuel cannot result in CO_2 benefits. (KG-25.20.) In addition, substituting natural gas for wood results in a net increase in CO_2 emissions. Also, the calculations should consider the extra energy that goes into manufacturing wood pellets. The net effect of these considerations is to increase the CO_2 emissions from the project by 14,571 tons over 10 years. (KG-25.21-22.) HPP also argues the pellet and gas stoves in the project would increase CO_2 emissions. (HPP-15.64-66.)

OE proposed there will be a net increase in CO_2 emissions from the wood stove program because the applicant will replace some wood stoves with natural gas stoves. OE assumes there is no net change in CO_2 emissions from replacing one wood stove with another. With the substitution of natural gas stoves for wood stoves, OE estimates that the annual CO_2 emissions will reach 11,464 tons by year 13 and remain at that level. OE did not account for the energy to manufacture wood pellets. (OE-11.35; OE-36.30-31.)

The Council finds that substituting gas stoves for wood stoves will result in a gross increase in CO_2 emissions of 11,464 tons by year 13 of the wood stove substitution project. In evaluating these projects the Council declines to account for upstream impacts. Consequently, we will not account for emissions related to manufacturing wood pellets.

ii. PM-10 offset

UGC estimates that replacing 1,100 existing wood stoves in Oregon with 400 certified wood stoves, 300 pellet stoves, and 400 gas stoves will result in an annual PM-10 reduction of 292 tons. (UGC Request 22.)

a. PM-10 emissions from uncertified wood stoves

UGC assumes that uncertified wood stoves in Oregon emit 50 lbs. of PM-10 per 1,000 lbs. firewood. It bases this on Oregon data from OMNI Labs in Beaverton, Oregon. It acknowledges that the U.S. Environmental Protection Agency (US EPA) assumes uncertified wood stoves emit 15.3 lbs. PM-10/1,000 lbs. firewood. (UGC Request C3-4.) It also claims a staff person at DEQ stated that 30-40 lbs./1,000 lbs. firewood was common for Oregon. (UGC-32.2.)

The Oregon Department of Environmental Quality uses an emission rate of 16 Lbs. PM-10/1,000 lbs. of firewood in assessing wood stove replacement programs, based on US EPA data. OE uses this rate. (OE-11.35.)

Of the evidence presented, the Council finds most persuasive the data used by the US EPA and the Oregon DEQ. The Council finds that the rate of 16 Lbs. PM-10/1,000 lbs. is the appropriate assumption to use in calculating the gross PM-10 offsets from wood stove replacements.

b. Wood use

UGC claimed an average wood consumption in old stoves of 3 to 4 cords per year per household. (UGC Request C4.) OE used an average of 3.5 cords per year. (OE-12.30.) UGC later claimed that a DEQ staff person stated that 3 to 5 cords of wood use per year per household was more realistic than the UGC assumption in its Application of an average use of 3.5 cords. (UGC-32.2.)

The Council finds that 3.5 cords per year is a reasonable estimate of wood consumption in wood stoves.

c. Heating value of wood

OE estimates the heating value of wood that will be used by the households receiving replacement wood stoves is 7,000 Btu/lb. This is lower than UGC's heating value, which implies UGC assumed drier wood. OE's assumption leads to a lower calculation of heat used by a typical household and has a small affect on the particulate matter form the wood stoves. We adopt the OE estimate for heating value (OE-11.35.)

c. Uncertainty

This proposal is moderately certain. Rather than proposing to offset a certain number of tons of PM-10 emissions, in this case UGC has proposed to replace a certain number of stoves. There is some risk that these replacements may not achieve the estimated savings, particularly since the estimates are based on a specific mix of three types of replacement stoves and that mix could change in practice. The actual performance of the replacement stoves also presents some uncertainty.

d. Monitoring and verification

UGC proposes that uncertified stoves replaced by its program will be destroyed at a recycling facility. The facility will issue a certificate of destruction. (UGC Request 22.) The implementation of the measure is thus readily verifiable. The Council would require as a condition of the site certificate that UGC report annually on the implementation of this measure. This reporting is sufficient to allow monitoring of the performance of the measure.

3. Adjustment factor

After consideration of the evidence, and considering the evaluation factors discussed above, we assign an adjustment factor of 0.8.

4. Offset

We adopt OE's calculations regarding the annual reduction in PM-10, ranging from 16 to 82 tons per year,depending on the number of stoves replaced and in operation. (OE-36.30.) The gross cumulative PM-10 offset at 30 or 100 years will be 822 tons. (OE-36.30-31.) The adjusted net PM-10 offset is 657 tons. (OE-36REV.2)

5. Monetized value

The net cumulative value of offsets from the wood stove replacement program will result in a monetized value of 0.01 mills/kWh. (OE-36REV.2)

G. Pacific Forest Trust Carbon Sequestration

UGC proposes to acquire approximately 1,000 to 2,000 acres of forest land easements that will increase carbon sequestration on existing understocked forest lands in Oregon and Washington. Alternative A has one-half the guaranteed CO_2 offsets that Alternative B has. Otherwise the forestry component of the two alternatives is identical. (UGC Request 14.) UGC prepared the proposal in cooperation with the Pacific Forest Trust (PFT), a non-profit organization active in forest research, conservation and management.

1. Evaluation factors

a. Timing

UGC commits to sequestration of a particular number of tons of CO_2 through forest management. (UGC-28.5.) The UGC Request for Exemption gave the CO_2 offsets at years 30 and 200. For purposes of direct comparison with the other applicant's proposals, OE relied on the calculations of likely offsets at year 100.

Based on UGC's projections, OE estimated offsets at year 100 as follows: 1,123,000 tons of CO_2 in Alternative B, and 561,500 tons in Alternative A. (UGC Request B-21, Table 3.) UGC proposes to verify the amount of carbon sequestered by PFT's STANDCARB analysis, a proprietary carbon sequestration model.

We adopt OE's analysis and conclude that the benefits from the PFT easements will continue through year 100.

b. Quantification

The proposal is based on important assumptions for both the reference and project case, including assumptions about the effectiveness of conservation easements, linkage of benefits to the easements, and leakage. (KG-25.23-27.) KG and HPP raised questions about the validity of the STANDCARB model and the credibility of the monitoring and verification plan. (HPP-27.18-21; HPP-20.3-8.) OE did not think the Council should rely on a proprietary model to verify the offsets, so it conducted its analysis without using the STANDCARB model. (OE-11.32.) HPP also raised questions about offsite carbon stores and the carbon decay rate (HPP-15.69-72.)

i. Effectiveness of conservation easements

UGC's proposal relies on acquiring conservation easements from willing forest landowners. A conservation easement is a non-possessory interest in land that either requires certain actions by or limits actions of the landowner. (UGC Request, B1-2, Ex. Sum.)

KG contends conservation easements are an untested and expensive means of sequestering carbon, better suited to other purposes, and that they result in substantial uncertainties. (KG-25.24-25; KG-37.136.) UGC testified about the history and use of conservation easements, specifically asserting that easements are an appropriate and cost-effective method of sequestering carbon. (UGC-31.09-10.) We find that a conservation easements are an appropriate method of sequestering carbon. (OE-11.32; OE-12.18-21.)

KG also argues that UGC provided no specifics as to the forest management plans that would bind the landowner-grantees. (KG-37.139.) OE concludes and we concur that sufficient information describing the plan has been provided and that a plan based on this description could be written and made enforceable through the easement.

ii. Additionality/Linkage of benefits

The proposed forest land easement program assumes that conservation easements will result in a change in the management regime for the project lands. Specifically, the program assumes that the easements will delay harvest, raise average stand age and accumulate additional carbon stores. (UGC Request 14-15.)

KG argues it is unlikely that the non-industrial private forest land (NIPF) trees covered by a conservation easement will have been clearcut in year 45 as assumed by UGC's reference case. KG claims UGC misstates Lettman's findings on this issue. KG claims Lettman provides empirical evidence for a 63-year average age for clearcutting and a 61-year average age for selective harvest of NIPF lands. (KG-25.29.) But KG in its posthearing brief and its witness, Dr. Mark Trexler, conceded that UGC relies on a different definition of privately-held land, from the U.S. Forest Service, which accounts for the differences in average age at harvest. (KG-31.14; KG-37.74.)

KG and HPP contend that it will be hard to determine if additionality is present; that is, whether conservation easements will produce management regimes and resulting CO_2 benefits that will not have otherwise occurred. (KG-35.35; HPP-27.16.) At the hearing, PFT's director testified that they would target individuals who have approached them about their program, which raises questions of additionality.

UGC testified and presented evidence from the Oregon Department of Forestry and the United States Forest Service that supported UGC's assumptions about the reference case management strategies for private, non-industrial timberlands. (Tr 681; UGC-31.11-12.) Furthermore, they will target timber stands that are 40-45 years old (Tr 683.) and owners managing their land for economic return. (Tr 686.) We are persuaded by UGC's evidence that conservation easements will produce CO_2 benefits that would not have otherwise occurred.

iii. Leakage

KG contends that UGC's proposed program presents a significant possibility of leakage that UGC did not address. (KG-25.34-35.) Specifically, KG asserts that the benefits of a forest protection program might "leak" if the program displaces harvesting pressure to another parcel. KG provided no evidence that such leakage would actually occur.

UGC responded that leakage was a hypothetical issue that could be neither proven nor disproved. (UGC-31.11.) UGC also maintained that management decisions of landowners were largely guided by personal reasons and would not be affected by the actions of a neighboring landowner. (UGC-31.11.)

We are not persuaded on this record that leakage presents a significant obstacle to carbon benefits from the UGC proposal.

iv. Validity of STANDCARB

UGC estimated project benefits by using STANDCARB, a proprietary forest carbon model. UGC proposes to evaluate future benefits through use of the STANDCARB model. (UGC Request 16.) HPP maintains that the model has not been subjected to serious independent review; and, therefore, UGC carbon offset estimates cannot be considered reliable. (HPP-27.18-21.)

OE conducted an independent review of the STANDCARB model results. (OE-11.31-33.) Although HPP argued that OE's review was not satisfactory (HPP-27.18-19.), OE testified that it checked the results of the STANDCARB model through independent calculations to its satisfaction because it did not think it was appropriate to rely on a proprietary model. (Tr 957-60.) Therefore, it developed its own spreadsheet to see if it could replicate the results of the STANDCARB model closely enough to give it confidence that the STANDCARB model's projections were credible estimates. By comparing its own spreadsheet estimates with those from STANDCARB, staff concluded that it is reasonable to assume that UGC could sequester the amount of tons it guarantees, 1.123 million tons of CO_2 on 1,400 to 2,000 acres of conservation easements in year 100. (OE-11.32; OE-37.6.)

OE did not propose that the Council use the STANDCARB model as a method to verify the carbon offsets. OE proposed a site certificate condition that UGC hire a panel of independent foresters and scientists acceptable to OE to review the conservation easements to determine if they are likely to achieve a benchmark level of sequestration by year 40 that will provide confidence that they can reach the 100-year target. (OE-11.30.)

We are persuaded by OE's independent review by its own forestry experts that the STANDCARB model provides reasonable estimates of carbon sequestration.

v. Offsite stores

HPP asserted that UGC did not accurately estimate off-site carbon storage benefits of the project because of weaknesses in its modeling techniques. (HPP-15.69-72.) UGC responded with testimony that clarified that the reference case and project case treated offsite stores the same and that HPP misunderstood the proposal. (UGC-31.2.) We accept UGC's assertion that it treated offsite stores the same for both the reference case and the project case.

vi. Decay rate of off-site storage

UGC used an estimated decay rate of 1.5 percent in its calculations. (UGC 31.2.) HPP argued that the decay rate UGC used was an unsupported assumption. (HPP-15.71-72.) UGC testified that the decay rate of 1.5 percent used in its calculations was based on the recommendation of Dr. Mark Harmon, a respected expert in the field. (UGC-31.2.)

The Council finds that the UGC's project assumptions are credible. The Council therefore finds it is likely that UGC can sequester its guaranteed target of carbon through the conservation easement program described in its application and subsequent testimony, subject to monitoring and verification independent of the STANDCARB model.

c. Uncertainty

Because PFT will likely rely on one or two landowners to obtain the necessary acreage, KG claims that this increases the uncertainty of the project. According to KG, this concentration increases the risk because of exposure to catastrophes such as fire or infection. While true, there is no showing that such catastrophes make it unlikely that the project will work nor any attempt to quantify that risk and providing the basis for adjusting the offset accordingly. In addition, such concentration enhances both enforcement of the easement and related forest management plan and monitoring.

KG also claims that the lack of information about the amount of land required, costs of acquiring the easement and other costs make this program more uncertain. (KG 37.139-41.) While precise information is not provided, UGC estimated that 1400 to 2000 acres need be acquired to sequester 1,123,000 tons of CO_2. Based on limited information in the record and the Council's general knowledge about power plant costs, there is no reason to believe (and KG provides us no such reason) that the cost for such acreage is so prohibitive an add-on to the UGC proposal creatingthat it creates uncertainty. While there exist some uncertainties regarding costs, we note that the KG's proposal have similar deficiencies and the nature of the proceeding requires the Council to decide the case with these deficiencies in mind.

d. Monitoring and verification.

UGC proposes a monitoring plan that will provide estimates of carbon storage at the project sites, calibrate and improve the STANDCARB model, and develop an efficient monitoring program for use in a wide variety of ecosystems and forest types. The monitoring plan relies on both field observations and measurements for calibration of the STANDCARB model and on aerial photography and remote sensing for biomass measurements. (UGC Request B12-14.)

OE proposed a site certificate condition to establish a panel of independent experts to review the UGC monitoring method for the conservation easements. If necessary, UGC will revise its method to ensure reasonably accurate estimates. (OE-11.30-31.)

HPP asserts the monitoring plan is not adequate to document the offsets from the PFT program. (HPP-20.4; HPP-27.22-24.) HPP claimed the monitoring plan is inadequate because it only monitors living biomass, it relies on remote imagery technologies that are still in an experimental phase, it has a conflict of interest by relying on PFT to do the monitoring, and the model has not verified its results with industrial management, which is the alternative case. (HPP-20.4-8.)

UGC presented rebuttal testimony that discussed the evolving nature of remote sensing and supported its reliability. (UGC-31.5-8.) UGC supported its field monitoring program by introducing its verification protocols for field measurements. (UGC-31.)

The Council is persuaded that the monitoring plan, in combination with the panel of experts recommended by OE, will provide valuable information about the performance of this offset.

3. Adjustment factor

Based on all of the foregoing, we conclude an adjustment factor of 1.0 to be reasonable.

4. Offset

We find UGC's guarantee under Alternative B, which will involve the acquisition of conservation easements on about 1,400 to 2,000 acres, will sequester at least 1,123,000 tons of CO_2 at 100 years. (UGC Request B-21, Table 3.) OE's independent calculations verify that amount is a reasonable guarantee, presuming that an enforcement mechanism is maintained to that date. (OE-37.6.) We find total CO_2 benefits of the Alternative B PFT program will be 1,123,000 tons. (OE-11.28-29, OE-36REV.2) We find that Alternative A will sequester at least 561,600 tons of CO_2. (OE-36.REV.2)

5. Monitized value of offset

Alternative A of the UGC PFT program will result in carbon offsets with a monetized value of 0.04 mils/kWh. The monetized value of Alternative B will be 0.09 mils/kWh. App B, Table 1.

H. Total Net Emissions and Net Monetized Value of the UGC Proposal

As set out above, we estimate that the gross emissions from the UGC energy facility will be 49,950,063 tons of CO_2, 7,231 tons of NO_x and 2,507 tons of PM-10 particulates. The adjusted value of emission offsets from Alternative A will be 552,329 tons of CO2 (561,500 from the PFT program minus 9,171 from the woodstove program) and 657 tons of PM-10. Alternative B will offset 1,123,000 tons of CO_2 and no NO_x or PM-10.

Total adjusted net emissions for alternative A will be 49,397,734 tons of CO_2, ,7231 tons of NO_x and 1,850 tons of PM-10. (OE-36REV.2.) Net emissions with Alternative B will be 48,827,063 tons of CO2, 7,231 tons NO_x and 2,507 tons of PM-10. (OE-36REV.2.)

Based on the net emissions, energy produced and values set out in OAR 345-01-010(35), we find the value of UGC's emissions with Alternative A will be 3.90 mils/kWh. (OE-36REV.2.) The value of UGC's emissions with Alternative B will be 3.86 mils/kWh. (OE-36REV.2)

VIII. CONCLUSIONS OF LAW REGARDING AIR IMPACTS

The values for net monetized air emissions are as follows:

proposal	mills/kWh	% difference from lowest
Klamath Cogeneration	3.10	lowest
HPP -- one unit	3.99	29%
HPP -- two unit	4.08	32%
UGC -- alt A (wood stoves)	3.90	26%
UGC -- alt B (forest mgt only)	3.86	25%

Under our rules we must determine whether the values for net monetized air emissions for the UGC and HPP proposals are "significantly greater" than values for the KG proposal. OAR 345-23-010 states: "Proposals that have values for net monetized air emissions per kWh net electric output that are not significantly greater than the proposal with the lowest value for monetized net air emissions shall be considered tied with that proposal."

We recognize that the use of the term significant requires line drawing, and that all line drawing may be viewed as somewhat arbitrary. Nevertheless some line drawing is necessary. Staff has proposed that in this proceeding "significant" should be 5% or greater. We believe that 10% is a more appropriate test.

In comparing the proposals, it is useful to consider the purpose of this proceeding. The proceeding arose from a recognition of the problems associated with climate change, and the fact that natural gas power plants, even very efficient ones, produce substantial amounts of carbon dioxide, the primary greenhouse gas.

We noted in the most recent order on power plant siting that the regional impacts associated with climate change could include "smaller snow packs, more winter precipitation; changes in the number and duration of summer droughts; further weakening of forest susceptible to degradation; an increase in frequency and severity of forest fires; disruption of the current operating regime for Pacific water resources, and impacts on fish, power generation, irrigation and navigation." We also noted that potential impacts include "the possibility of permanent flooding of low lying areas causing estuaries and open coastal areas to retreat inland or disappear and exaggeration of the impact of coastal storms, which could cause damage to buildings and highways." We noted that the possibility that "Highway 101 would have to be moved in places, that parts of Garibaldi would be flooded, and that Tillamook would have a waterfront." HPP Final Order at 88.

These are clearly serious and significant impacts. Although we were unable, on the record in that contested case, to determine that the emissions associated with the plant had a direct impact to the public health and safety, we are cognizant of the indirect and cumulative impacts associated with CO_2 emission. These indirect and cumulative impacts are the reason for the approach we took in structuring this proceeding.

In adopting this rule, there was considerable discussion of the circumstances in which two proposals would be considered tied. Initially staff had proposed the use of a 10% differential. However, it was pointed out that 10% might be too high a number, because the proposals made may call for significant expenditures, and 10% of a large number is also a large number. In the end we decided to wait and see what the proposals were, and to make the judgment of significance at that point. After reviewing the size and types of proposals, we believe that a 10% test is appropriate.

KG's proposal has the lowest value for monetized net air emissions. The closest proposal, UGC Alternative B, is 25% higher than the KG value. We find that the values for net monetized air emissions per kWh net electric output of all other proposals are significantly greater than the value for KG's proposal.

IX. FINDINGS OF FACT AND CONCLUSIONS OF LAW: IMPACTS TO WATER

Although our conclusions under the exemption rule regarding net monetized air emissions fully resolve the contested case proceeding, we analyze the proposals under the secondary and tertiary criteria of the exemption rule in the event that this decision is reversed on judicial review. Under the exemption rule, proposals are next evaluated in terms of consumptive use of water and discharge of waste water under OAR 345-23-010(2)(c). The rule states:

> (c) If two or more proposals are tied for lowest value of monetized net air emissions under subsection (2)(b) of this rule, the exemption shall be awarded to the tied proposal with the lowest impact, as evaluated by the Council, on water.
>
> (A) Impacts on water include:
>
> (i) Consumptive use of water considering the quantity, quality, source and alternative uses of that water, and
>
> (ii) Net discharges of waste water considering the quantity, quality, source and disposition of wastewater. The Council shall consider reduction in discharges that result from the beneficial use of waste water produced by the facility and for waste water used by the facility that would otherwise be discharged by another industrial, commercial or municipal process.
>
> (B) Proposals that have impacts on waste and waste water not significantly greater than the proposal with the lowest impacts, as evaluated by the Council, shall be considered tied with the proposal with the lowest impact on water and wastewater.

The text of the rule requires an evaluation of gross water consumption rather than on the basis of water consumed per kWh. The air emissions part of the rule, OAR 345-23-010(2)(b), specifically requires that the proposals be evaluated on the basis of their monetized net emissions per kWh. In contrast, the parts of the rule addressing the impacts on water and land use, OAR 345-23-010(2)(c) and (d), do not call for comparison on a per kWh basis. While this may have been the result of inartful drafting, we are bound by the clear language of the rule to evaluate on the basis of gross water consumption.

A. Consumptive Water Use

1. Umatilla Generating Project

UGC will withdraw water from the Columbia River through an existing water right held by the Port of Umatilla. UGC holds a contractual right to use up to 2,600 gallons per minute (gpm). (UGC Request 31.) UGC will withdraw an average of about 2,000 gpm. (Tr 1005.)

The only discharges from the facility will be about 500 gallons per day of sanitary wastes, which will be disposed to an on-site septic system. All storm water on the power island will be collected and reused in the cooling water system. There will be no plant contaminates from runoff from other parts of the site. (UGC Request 33-34.)

All of the water withdrawn from the Columbia will be evaporated to the atmosphere. About 140 tons per month of residual salts from treatment processes and salts in the Columbia river water will be disposed of in a local sanitary landfill. (UGC ASC Exhibit F, p.2.)

2. Hermiston Power Partnership

HPP's Two Unit Project alternative will require 1969 gpm of make-up water while the One Unit Project will require 985. HPP will obtain its plant water through the Port of Umatilla. HPP has the right to withdraw up to 2,400 gpm. (HPP Request p. 16.)

For the Two Unit Project, net discharges (excluding sanitary waste) will consist of 144 gpm of wastewater that will be disposed of by the adjacent Simplot plant through land application for crop irrigation. Net consumption would be 1825 gpm [1969-144=1825]. For the One Unit Project net discharges will be 72 gpm of wastewater to land application. Net consumption will be 913 gpm [985-72=913]. (HPP Request p. 16.) Sanitary waste will go to the Simplot Plant to be disposed of with Simplot's other sanitary waste.

3. Klamath Generation Project

The Spring Street Wastewater Treatment Plant (SSWTP) will supply about 1,332 gallons per minute of treated effluent to the KG Project for cooling water requirements. (KG Request 4-2.) The KG Project will also use about 129 gpm of potable water, which will be discharged to the SSWTP. (KG Request 4-2.) The project will return about 436 gpm to the SSWTP. (KG Request 4-3.) Thus, the KG project will consume 1025 gpm [1332+129=1461-436=1025].

4. Comparison of consumptive water use impacts

The water sources are not the same for all projects. The consumptive water use by the KG project represents about 0.8 percent of the lowest monthly flow of the Klamath River during the period 1951 to 1981. (UGC-28.11.) The UGC project and the HPP Two Unit Project water use would be less than 0.008 percent of the lowest monthly river flow in the Columbia over the same period. (UGC-28.11.)

The Oregon Water Resources Department reports that the State's pending water right for instream flow in the Klamath River 20 miles downstream from the KG Project is commonly not met during summer months even without the KG Project. In roughly half of the years, the flows in the river are less than 40 percent of the pending instream water right. (UGC-28.101.) There is no evidence in this case of similar impacts on pending water rights or uses of the Columbia River.

B. Discharge Of Waste Water

The HPP, KG and UGC projects all evaporate large amounts of water for cooling. Evaporation leaves behind the salts already present in the source water (Columbia River or SSWPT effluent) as well as the salts that each project must add to treat its water. In general these salts are discharged in each project's wastewater. There is no evidence that any of the projects add more salt or add different types of salt that would have different impacts on the environment. However, there are differences in how the projects dispose of their wastewater.

1. Umatilla Generating Company

UGC proposes a zero-wastewater discharge system. No wastewater will leave the project site. UGC salts will end up as about 140 tons per month of filter cake. This will be hauled to a regional landfill. There is no evidence these salts will have an impact on the local environment.

The other applicants argued that there is water used offsite in the UGC system for periodic cleaning of the filter system. The evidence on this point was scant, and involved practices at the Hermiston Generating facility, not the UGC facility. The evidence does not support the claim that the UGC facility will use water off-site.

2. Hermiston Power Partnership

HPP wastewater will be discharged to the adjacent Simplot potato plant where it will be land-applied for crop irrigation. HPP Request p. 17. This method of disposal has been approved by the Oregon Department of Environmental Quality (HPP Request, p. 18.) UGC argued that it appears questionable whether the use of HPP's wastewater for irrigation will displace existing water withdrawals for irrigation by the Simplot potato plant. (UGC-28.15.) If withdrawals are not displaced, total salts applied to irrigated lands in the area will increase.

The land application of 144 gpm of HPP effluent (or 72 in the case of the One Unit Project) to local irrigation is a beneficial use. However, land application of effluent may increase salt in soils or groundwater. Overall, the Council finds that concerns about salt build-up outweigh the benefit from the beneficial use of the water.

3. Klamath Cogeneration Project

KG's wastewater will be returned to the SSWTP where it would be treated along with other influent and then discharged to the Klamath River. KG's salts will be discharged to the Klamath River in the effluent from the SSWPT. There is no evidence these salts will have an impact on uses of the Klamath River.

However, the KG project's use of effluent from the SSWTP as the primary source of cooling water, its wastewater discharge to the SSWTP and the ultimate discharge of KG project wastewater to the Klamath River result in an additional water quality consideration.

In its Request for Exemption KG states, "Net wastewater discharges * * * are less than zero (-896 gpm or -0.176 g/kWh). This represents a net water use benefit rather than a net impact from the project." (KG Request 4-5.)

UGC states that Klamath's use of effluent will not have a positive impact on Klamath River water quality. UGC asserts that virtually all of the contaminants in the sewage effluent taken in by the KG project will be returned to the river. (UGC-16.2-16.3.)

OE states that Klamath's use of effluent will have a positive impact on Klamath River water quality. Because the concentration of the effluent is limited by the Oregon DEQ, the large reduction in the volume of effluent will result in a large reductions in total BOD loadings. (OE-11.36-11.41.)

HPP asserts that the BOD concentration of influent to the sewage plant "could increase (from 170) to 280 mg/L." This apparently assumes inflow will drop from 2,300 gpm to 1400 gpm, a drop of 900 gpm. If so, the treatment removal of the SSWTP would need to rise to 95 percent (14/280 mg/L), to retain the current 14 mg/L effluent concentration (HPP-22.6.)

KG rebuts HPP concern about increased influent concentration at the SSWTP. KG notes that the treated effluent the KG project returns to the SSWTP will be concentrated to only 60 ppm (mg/L) (Tr 1097, l 20.) Adding this to the SSWTP influent stream of 170 mg/L of will dilute it to about 150 mg/L (Tr1101, l 5-7.)

KG asserts that "The SSWTP (Spring Street Wastewater Treatment Plant) will operate its treatment system as it currently does to meet the plant performance levels." KG asserts that this will result in "less BOD being discharged to the Klamath River." (KG-29.2.)

UGC challenged KG's assertion of decreased BOD loadings. UGC notes that "the City (of Klamath Falls' SSWTP) is substantially below their permit limits for BOD, the permit limits are (in and of themselves) not a constraint on increases in BOD loading or concentration." (UGC-30.2, l 20-23.)

OE asserted that under the current National Pollution Discharge Elimination System (NPDES) permit, the SSWTP effluent BOD concentration could rise from the current level of 14 mg/L only up to the NPDES permit maximum of 20 mg/L. OE asserted this will still result in a net reduction in the BOD loading to the Klamath River of about 100 pounds per day because of the 896 gpm reduction in SSWPT effluent to the river. Moreover, if the BOD concentration were to remain at 14 mg/L, the BOD loading to the Klamath River will drop by about 200 pounds per day.

Detailed calculations[8] indicate the reduction in BOD loadings to the Klamath River will range between 75 and 150 lb./day based on

[8]The SSWTP effluent flows under low flow conditions will be reduced by the KG project from 1944 gpm (2.8 mgd) (TR 1098, l 15) by 896 gpm (KG-29.1.). This yields a new flow of 1048 gpm or 1.51 mgd (1048 gpm * 24 hr/day * 60 min/hr). The total BOD loading under the current flow and concentration would be 326 pounds per day (2.8 mgd * 3.78 L/gal. * 14 mg/L * 2.2 lb/Kg). Under the new flow (ie with the KG project) total loading would range from 251 pounds per day, if effluent concentration rises to 20 mg/L (1.51 mgd * 3.78 L/gal. * 20 mg/L * 2.2 Kg/lb.), to 176 pounds per day if the concentration remains constant at 14 mg/L. (1.51 mgd *3.78

SSWPT effluent BOD concentrations of 20 mg/L and 14 mg/L respectively.

We find that a reduction in BOD loadings to the Klamath River of 75 to 150 lb./day represents the range of likely impacts of the KG project. The reference case BOD loading under low flow condition is 326 lb./day. Therefore, likely reduction is 23 to 46 percent in SSWTP BOD loading under low flow conditions. Given that Oregon DEQ regulates the SSWTP as one of five major sources of BOD on the Klamath River (Tr 1096.) and given DEQ has designated Lake Ewauna downstream from the SSWTP as water-quality limited (Tr 1092.), we find the KG project will have a substantial beneficial impact on Klamath River water quality.

C. Discussion and Conclusions.

Following is a table summarizing the water impacts of the various proposals:

	amt of consumptive use	negative impact?	discharge	negative impact from discharge	positive impact from discharge
HPP -one	985 gpm	no	ground	salt onto ground	
HPP -two	1825 gpm	no	ground	salt onto ground	
UGC	2000 gpm	no	zero		
KG	1025 gpm	yes; decrease stream flow	river	salt into river	reduce BOD in river

The exemption rule requires us to determine whether any proposal has impacts to water that are "not significantly greater than" the proposal with the lowest impact. To make this determination we rely on our definition of "significant," which provides:

L/gal * 14 mg/L * 2.2 Kg/lb.). These values bound the range of the change in BOD loadings from 75 lb.day (326 - 251) to 150 lb./day (326 - 176).

> "(45) "Significant" means having an important consequence, either alone or in combination with other factors, based upon the magnitude and likelihood ofthe impact on the affected human population or natural resources, or on the importance of the natural resource affected, considering the context of the action or impact, its intensity and the degree to which possible impacts are caused by the proposed action. Nothing in this definition is intended to require a statistical analysis of the magnitude or likelihood of a particular impact."

OAR 345-01-010(45).

Consumptive water use:

Given what the record shows about the volume of total flow in the Columbia and the percentage of that flow that the UGC project and the HPP one and two unit projects represent, the difference between the UGC's total consumption of about 2,000 gpm and the HPP One Unit Project's total consumption of 985 gpm does not have an important consequence for the Columbia. KG total consumptive use is 1025 gpm. That consumptive use has an important consequence because it is in a river with significant low flow issues.

Discharge:

The KG project will result in a reduction in BOD loading in the Klamath River. HPP will discharge wastewater onto land to irrigate farmland. UGC will not discharge any water.

Salts:

It is unclear if the impact of salt added to irrigated lands near the HPP plant is of greater or lesser concern than increased salt concentrations to the Klamath River from the KG plant. While we believe the salt disposal into the landfill is preferable, we have no basis for finding that discharge of salts into rivers or onto land will have a significantly greater impact.

Ranking:

KG's reduction of BOD discharge has important beneficial consequences for water quality in the project vicinity. But the project will reduce downstream flow in a river that currently does not have adequate flows over half the summer. This is an important negative consequence. The Council finds that of the three proposals, the KG project is likely to have both the greatest negative impact and the greatest positive impact. The Council finds these conflicting impacts to be of roughly equal magnitude.

In general, the Council considers this kind of variance to be negative. The uncertainty is greater for the KG project since we do not know if the positive impacts are larger or smaller than the negative impacts. Generally, imposing increased uncertainty on the public and the environment is undesirable. The Council finds this uncertainty represents a greater negative impact on water by the KG Project than posed by the other projects.

The HPP and UGC projects pose no such impacts overall. Therefore, they are superior.

The Council concludes that the differences between UGC and HPP do not indicate that one will have a significantly greater negative impact on water. The consequences to the affected resources are roughly the same.

The KG project ranks last, because the variance in positive and negative impacts of KG's water use creates greater uncertainty as to its overall impact on water. The question then becomes whether the uncertainty arising from the KG proposal has a "significantly greater" impact on water than do the UGC or HPP projects. We conclude that the impact to the Klamath River system from the KG proposal is not of greater consequence than the impact from the HPP or UGC proposals on the Columbia River system. Therefore, we conclude that the projects are "tied" as to their water impacts.

X. FINDINGS OF FACT AND CONCLUSIONS OF LAW: LAND USE

We have determined earlier in this order that KG is significantly superior to the other proposals in its net monetized air emissions. We make the following findings of fact and conclusions of law under OAR 345-23-010(2)(d) in the event that determination is reversed on judicial review and a determination under this portion of the rule becomes necessary.

OAR 345-23-010(2)(d) defines the third level of inquiry where two or more facilities have tied in the categories of net air emissions and on water impacts. At this level, the inquiry focuses on impacts within four broad land uses -- farm and forest uses outside the urban growth boundary, existing uses within urban growth boundaries, wildlife uses and scenic values. The rule provides:

"(d) If two or more proposals are tied in terms of water and waste water impacts under subsection (2)(c), the exemption shall be awarded to the tied proposal with the least detrimental impact from related or supporting facilities as evaluated by the Council. The Council shall consider impacts from related or supporting facilities on land use.

(A) Land use impacts include:

(i) Farming and forestry land uses outside the urban growth boundaries;

(ii) Existing land uses within urban growth boundaries;

(iii) Wildlife; and

(iv) Scenic values.

(B) Proposals that have impacts from related or supporting facilities that are not significantly greater than the proposal with the least detrimental impact, shall be considered tied with the proposal with the lowest impact.

Applicants have the burden of proving that their proposal has "the least detrimental impact from related or supporting facilities as evaluated by the Council," by a "significant" margin. OAR 345-23-010(2)(d). As for water impacts, we rely for assistance in making this determination on our definition of "significant," set out above. "Related or supporting facilities" are defined in OAR 345-01-010(43) as follows:

> "Any structure proposed to be built in connection with energy facility * * * 'Related or supporting facilities' does not include any structure existing prior to construction of the energy facility, unless such structure must be significantly modified solely to serve the energy facility."

KG argues that the impact on the first category--farm land--is the primary one based on being listed first and the importance that Oregon land use goals place on preserving farm land. Our listing of four impacts without prioritizing was intended to require equal consideration of each impact. Indeed, in our site certificate rules and proceedings no effort is made to place one of these considerations above the others. Given that context, it would be inappropriate to give priority here, as KG suggests.

The first part of the rule requires an evaluation of farm and forest uses outside of urban growth boundaries. For this evaluation, we focus on the amount of farm or forest land taken permanently out of production by the related or supporting facility.

For the second category of land use impacts, the rule directs our attention to *existing* uses within urban growth boundaries. The rule does not use that qualifying language with respect to farming and forest land uses outside urban growth boundaries, and we do not imply such a qualifier. We therefore focus on existing uses within urban growth boundaries, to the extent the record allows us to do so, and on farm and forest zoning classifications outside the urban growth boundaries.

For existing uses within urban growth boundaries, we adopt as our primary decisional criterion the miles of new transmission construction in areas currently used for residences. The Council has had experience with siting transmission lines, both recently and in the past. The Council issued a site certificate to PacifiCorp in 1982, and last amended the certificate in 1990 for a 500 kV transmission line from Eugene to Medford. The Council has also issued three site certificates in the recent past, one to the Hermiston Generating Co. for a facility in Hermiston, one to Portland General Electric for its Coyote Springs facility in Boardman, and one to Hermiston Power Partnership for a facility in Hermiston. Each included a high voltage transmission line.

We have learned from our experience with these facilities that the predominant land use concern about new transmission lines arises among owners of residential property along the route of a new line. Concerns have ranged from health effects from electromagnetic fields to the perception of health effects from electromagnetic fields and the resulting effect on property values, to the visual impact of a new transmission line near a residence. In our experience, no other land use impacts produce the effects created by new lines near existing residences. Consequently, for existing land uses within urban growth boundaries, we will rank these facilities according to the number of miles of new transmission line that will be constructed in areas used for residences.

KG argues that we should distinguish, and attribute less negative impact to, new transmission line construction within an existing right of way. Although we acknowledge that in some cases, depending on the size and configuration of the existing line and the new proposed line, the impact of new construction may not have negative impacts, we do not believe the record is sufficient for us to draw such a conclusion with respect to the KG proposed transmission line. We would need more design detail than is available in this record in order to make that determination. Consequently, we do not distinguish between new construction in existing corridors and new construction outside existing corridors.

The third and fourth parts of the rule focus on impacts on wildlife and scenic values. We conclude, based on the facts in the record set forth below, that there are not significant differences between the three facilities with respect to these two types of impacts.

For the purpose of calculating permanent disturbance from related or supporting facilities, we assume six transmission line pole structures per mile and disturbance of 150 square feet per pole structure. None of the other related or supporting facilities would create permanent disturbance to farm land.

A. Umatilla Generating Project

The related or supporting facilities for the UGC energy facility are (1) new transmission line interconnections aggregating approximately 0.54 miles in length at the project and at the McNary substation; (2) addition of conductors and insulators to a segment of the existing 115/230 Kv Westland-McNary transmission line approximately 11.7 miles in length; (3) a new natural gas pipeline approximately 5.4 miles in length that would connect the project to an existing Pacific Gas Transmission pipeline; and (4) a new water supply pipeline approximately 0.5 miles in length that would connect the project to the Port of Umatilla water line serving the Hermiston Generating Project. (OE 11.41.)

Related and supporting facilities will have a small to negligible effect on wildlife. The transmission line involves very little new construction. Sensitive bird species that could be affected by construction activities during the nesting season would be protected by a site certificate condition requiring construction activities to occur outside of "sensitive time periods" where feasible. An additional condition will require that areas disturbed by construction activities be revegetated with appropriate plant species to the extent feasible. (OE 11.44-45.)

A portion of the upgraded transmission line and its interconnections will be visible from the McNary Lock and Dam. However, after completion of construction, this portion will be indistinguishable from existing transmission lines. These related and supporting facilities will not be visible from any other of the scenic areas, nor obscure the view of any other of the scenic areas, within the project impact area for scenic impacts. (OE 11.45.)

The UGC project will permanently disturb .010 acres of farm land outside the urban growth boundaries and will involve no new transmission line construction in areas with existing residential uses. (OE 33 as corrected in Larson cross-examination p. 1203, lines 4-6.)

B. Klamath Cogeneration Project

The related or supporting facilities for the KG energy facility are: (1) a new 230 Kv transmission line approximately 3.1 miles in length that will connect the project to an existing Pacific Power and Light substation; (2) a new natural gas pipeline less than 100 feet in length that will connect the project to an existing Pacific Gas Transmission pipeline that runs through Weyerhaeuser property adjacent to the project site; (3) a new 14-inch water supply pipeline approximately 6.1 miles in length that will connect the project to the City of Klamath Falls' existing wastewater treatment plant; (4) a new 8-inch wastewater pipeline approximately 1.7 miles in length that will connect the project to the City of Klamath Falls' existing sewer system; (5) a new 6 inch potable water supply pipeline approximately 1.0 mile in length that will connect the project to an existing City of Klamath Falls' water main; and (6) new steam and condensate return pipelines approximately 1.2 miles in length that will connect the project to the Weyerhaeuser plant. (OE 11.45-46.)

KG's energy facility will involve construction of 0.8 miles of new transmission line in areas with existing residential uses. Its related or supporting facilities will not permanently disturb any farm land outside the urban growth boundaries. (OE 33.)

KG notes that its transmission line will be in or alongside existing transmission line right-of-ways. OE, based on its experience with transmission line site certification processes, recognizes that even the addition of lines alongside existing lines is likely to be a concern to nearby residential users. Therefore, OE declined to discount the impact on these new lines. (Tr 1215-17.) For the reasons we stated above, we concur in this approach.

The KG energy facility's related or supporting facilities will have little or no effect on wildlife because the facilities will be routed through areas that have low value to wildlife because of previous disturbance for industrial purposes, or along existing service corridors. Species most likely to be affected are common to the region and no designated habitat areas would be disturbed. Potential effects on the Link River, Klamath River and Lake Ewauna, essential wintering habitat for bald eagles and waterfowl, will be avoided by locating the proposed transmission line outside of a quarter-mile buffer zone, as recommended by the Oregon Department of Wildlife. (OE 11.48-49.)

The proposed transmission line, the only visually prominent related or supporting facility associated with the project, would not be visible from any of the scenic areas, nor obscure the view of any of the scenic areas, within the project impact area for scenic impacts. (OE 11.49.)

C. Hermiston Power Project

HPP’s site certificate authorizes it to use one of two transmission line options. Consequently, we describe each alternative, but evaluate the HPP facility in this category on the basis of the land use impacts for the alternative with the greater impacts, the 500kV alternative.

1. 230 kV Option

The related or supporting facilities for this option are: (1) a new 230 kV transmission line approximately 3.6 miles in length that will connect the project to the existing Westland substation; (2) addition of new conductors and insulators to an existing 115/230 kV transmission line approximately 12.3 miles in length connecting Westland substation to the BPA McNary substation; (3) a new 12 inch natural gas pipeline approximately 8.8 miles in length that will connect the project to an existing Northwest Gas pipeline; (4) a new 12 inch natural gas pipeline approximately 4.1 miles in length that will connect the project to an existing Pacific Gas Transmission pipeline; and (5) a new 16 inch water supply pipeline approximately 1.1 miles in length that would connect the project to the City of Hermiston/Port of Umatilla Regional Water System water treatment plant. (OE 11.49-50 as corrected by HPP 26.7.)

For this option, HPP proposes to use the same existing transmission line as does UGC. The line is owned by the Umatilla Electric Cooperative Association, which has not yet decided whether or how to provide transmission service to UGC or HPP. (Tr 1245.) The UGC facility will be required as a condition of the site certificate to have access on this route before beginning construction, as will the HPP facility, unless it chooses the 500 kV option described below. The transmission line impacts for this option are thus very similar for UGC and HPP, with the only differences involving interconnections at either end of the required route.

HPP's related and supporting facilities will have a small effect on wildlife. The transmission line involves very little new construction. Sensitive bird species that could be affected by construction activities during the nesting season will be protected by a site certificate condition requiring construction activities to occur outside of "sensitive time periods" where feasible. An additional condition would require that areas disturbed by construction activities be revegetated with appropriate plant species to the extent feasible. Total wetland disturbance of approximately 0.007 acre will be subject to revegetation after completion of construction. (OE 11.53-54.)

As is the case for the UGC energy facility, a portion of the upgraded transmission line and its interconnections would be visible from the McNary Lock and Dam. However, after completion of construction, this portion will be indistinguishable from existing transmission lines. These related and supporting facilities will not be visible from any other of the scenic areas, nor obscure the view of any other of the scenic areas, within the project impact area for scenic impacts. (OE 11.54.)

The HPP energy facility's 230 kV option will permanently disturb .041 acres of farm land outside urban growth boundaries. It will not involve construction of new transmission lines in areas with existing residential uses. (HPP-26.12; OE-32.)

2. 500 kV Option

The related or supporting facilities for this option differ from the 230 kV option only with respect to transmission lines: (1) a new 500 kV transmission line approximately 14.2 miles in length (0.8 miles of which will use existing structures [HPP 26.14-15]) that will connect the project to the existing BPA McNary substation; and (2) a relocated 500 kV transmission line approximately 0.9 miles in length near the existing BPA McNary substation. The water and gas pipeline facility descriptions are set forth under the 230 kV option. (OE 11.54-55.)

The 500 kV transmission line option will have small effect on wildlife because it will be located largely within existing utility corridors. Total wetland disturbance of approximately 0.084 acres will be subject to revegetation after completion of construction. (OE 11.58.)

The new transmission line and the relocated BPA transmission line are the only visually prominent related and supporting facilities associated with the project. A portion of the relocated BPA transmission line will be visible from McNary Lock and Dam. However, the McNary substation and many associated transmission structures are also clearly visible from the lock and dam. Thus the visual impact will be minimal. The related or supporting facilities will not be visible from any other scenic areas, nor obscure the view of any other scenic areas, within the project impact area for scenic impacts. (OE 11.59.)

The HPP energy facility's 500 kV option will permanently disturb .103 acres of farm land outside urban growth boundaries and will require 1.00 mile of new construction in areas with existing residential uses. (OE 33 as corrected in Larson cross-examination p. 1203, lines 6-7.)

D. Discussion

The UGC facility involves no new construction in areas with existing residential uses and will take only 0.01 acres of farm land out of production. It requires only one-half mile of new transmission line construction: into an existing substation, which already supports many transmission lines, and the short distance from the energy facility to an existing line. None of that new construction is in areas currently supporting residential uses. Both the KG transmission line and the HPP 500 kV alternative will require routing through residentially used areas.

The Council recognizes that the likelihood of a negative impact from new transmission line construction on nearby residents is high, as is the perceived magnitude of that impact. In our experience, new transmission lines have potential to cause such consternation among nearby residents, because of problems either real or perceived, that any reduction in impact to those residents has an important consequence, i.e. is a significant benefit. Therefore, we conclude that the impact of the KG and the HPP 500 kV proposals are significantly greater than the UGC proposal with regard to impact on nearby residents.

With respect to farm land taken out of production, our experience has not given us the basis to conclude that the small differences between facilities on this parameter are significant.

E. Conclusion

The Council concludes the UGC facility has the least detrimental impact from related or supporting facilities. The KG facility and the HPP 500 kV line have significantly greater impacts.

XI. FACILITY WITH THE OLDEST COMPLETE APPLICATION

Under OAR 345-23-010(2)(e), if two or more proposals are tied in having the least detrimental land impact from related or supporting facilities under OAR 345-23-010(2)(d), the exemption shall be awarded to the proposal with the oldest application determined to be complete by the OE.

OE deemed HPP's application for site certificate complete on April 14, 1995. UGC submitted an application on March 1, 1996, which OE has not yet determined to be complete. KG submitted an application in February, 1996, which OE similarly has not yet determined to be complete. Therefore HPP is not only the oldest, but also the only, applicant whose application OE has determined to be complete. (See Rec 174.) ("If it got through to a tie, in all cases, I think, HPP would win. They have the oldest application deemed complete on the list.") (Charlie Grist).

We conclude that HPP is the oldest application determined complete and prevails under OAR 345-23-010(2)(e).

XII. CONCLUSION AND CONDITIONS

Based on the findings and conclusions set forth above, we award the exemption to KG.

Under the exemption rule, the Council may credit offset measures only if they are "guaranteed by an assurance bond or performance bond or can be made binding through other site certificate conditions." A cogeneration offset must also be "made binding through site certificate conditions." OAR 345-23-0010(2)(b)(C). As discussed earlier in the Order, this requirement may be satisfied by binding the applicant to implement its offset proposals, including cogeneration. Mitigation measures and cogeneration may be made binding through site certificate conditions. Attached to this order as Appendix A are conditions to bind KG to implement the programs, and achieve the cogeneration, that it has proposed. The council intends to impose these conditions in KG's site certificate if KG demonstrates compliance with all EFSC site certificate criteria.

These conditions satisfy the requirements of the exemption rule, generally ensure implementation of the mitigation programs and cogeneration, and effectuate the policies underlying the rule and this proceeding.

Issued this ______ day of August, 1996.

Terry Edvalson, Chair
Energy Facility Siting Council

RIGHT TO JUDICIAL REVIEW:

You have the right to appeal this Order to the Oregon Court of Appeals pursuant to ORS 183.482. To appeal you must file a petition for judicial review with the Court of Appeals within 60 days from the day this Order was served on you. If this Order was personally delivered to you, the date of service is the day you received the Order. If this Order was mailed to you, the date of service is the day it was mailed, not the day you received it. If you do not file a petition for judicial review within the 60 day time period, you will lose your right to appeal.

APP. A
SITE CERTIFICATE CONDITIONS

1. KG shall make available to its steam host at least 200,000 pounds of steam per hour on an annual basis. The average steam pressure shall be not less than 375 pounds per square inch gauge. The average steam temperature shall be not greater than 455 degrees F. The amount, temperature and pressure of steam supplied shall be measured at the point of interconnection of the energy facility with the steam host. KG shall report this information to the Council on an annual basis.

   KG's steam host shall use at least 200,000 pounds of steam per hour on a five year basis. At the end of each five year period following commercial operation, KG shall determine and report to the Council the hourly average steam delivered to its steam host for the applicable five year period. Should the hourly average steam used by KG's steam host be less than 200,000 pounds per hour, KG shall develop, present to the Council for approval, and implement a plan to make available and sell to another steam user the amount of steam not used by KG's existing steam host at the same or similar cost incentive as provided to KG's existing steam host. If within twelve months after Council approval, KG has not contracted to make available and sell to another steam user the amount of steam not used by KG's existing steam host, then KG shall develop, present to the Council for approval, and implement a program to offset an amount of CO_2, NO_x or PM-10, or any combination thereof, equivalent to the monetized incremental emissions resulting from the steam host's use of less than an average of 200,000 pounds of steam per hour. In any event, KG shall offset an amount equivalent to the monetized incremental emissions resulting from the steam host's use of less than an average of 200,000 pounds of steam per hour, measured on a five year basis, for 30 years.

2. KG shall provide to the Council an executed steam sales contract with Weyerhaeuser before beginning construction.

3. Before commencing construction, KG shall establish an escrow account in the amount of $3.1 million for implementation of the offset portfolio described in its Request for Exemption.

4. Before commencing construction, KG shall commence good faith implementation of its offset portfolio.

5. If the facility does not achieve commercial operation, KG's obligation to further fund and implement the offset portfolio shall end and any remaining funds shall revert to KG.

6. Before commencing constructing the facility shall make available a contingency account in the amount of $300,000 in 1996 dollars. The contingency account may be drawn upon in years 10, 20 and 30 to provide additional funding in the event the mitigation portfolio is not meeting projections, within 10 percent. In the event the effects of actual CO_2 mitigation are less than 90 percent of projected CO_2 offsets after 10, 20 and 30 years, and if cogeneration or other offsets do not compensate for this increase (including offsets resulting from reduced methane emissions based on the then-prevailing IPCC CH4-CO_2 equivalency factor), KG shall make a sum up to the total amount of the contingency fund available to purchase or fund additional CO_2 offsets. The contingency fund available in years 10, 20 and 30 shall comprise the remainder of the contingency fund less additional funding draws in years 10 and 20, respectively. Any unused portion of the fund shall revert to the project after year 30.

7. Any financial returns associated with implementation of KG's carbon offset portfolio during the first 30 years shall be reinvested in carbon offset portfolio activities as proposed in the request for exemption. At year 30, KG shall consult with the Council regarding the disposition of any financial returns after year 30. At the Council's discretion, these returns may either be invested in additional CO_2 mitigation activities or may be redirected to other environmental purposes.

8. On implementation of its offset portfolio, KG shall undertake the offset monitoring and verification programs described in its Request for Exemption. KG shall annually report offset performance to the Council and the U.S. Department of Energy Section 1605(b) greenhouse gas registry. KG will make available up to $50,000 per year, in 1998 dollars, for this monitoring and verification program.

9. KG shall make its offset portfolio financial records available for auditing by the Council or a designated party for the life of the facility, provided that the cost of such auditing shall be paid by the Council.

10. Every five years for the life of the facility KG shall report to the Council offset portfolio performance, associated CO_2 and methane benefits, and explain changes from the offset benefits projected in the Council's analysis of KG's request for exemption.

11. KG shall consult with the Council on an ongoing basis regarding portfolio emphasis and performance. As requested by the Council, and to the extent made possible by in-place agreements, KG shall reallocate available funds among its portfolio or other projects requested by the Council.

12. Subject to potential reallocation of funds described in Condition #11, of the $3.1 million in the escrow fund, $0.5 million shall fund the Solar Electric Light Fund (SELF), $1.5 million shall fund the Oregon Forest Resources Trust (FRT), $1.0 million shall fund new projects to generate electricity with otherwise waste methane, and $0.1 million shall fund geothermal heating projects in Klamath Falls, Oregon, as described in the Request for Exemption.

13. KG shall commit $1.0 million of the $3.1 million escrow fund to fund new projects to generate electricity with otherwise waste methane from sewage treatment plants and coal mines. The projects shall be administered by Northwest Fuel Development, Inc., or an equivalent contractor, at KG's discretion. Net revenues from the installation of each electrical generation facility shall, for a period of ten years, be returned to a Revolving Investment Fund (RIF) established by KG. KG shall structure the RIF so that net revenues from each installation financed by KG's original capital investment will be used to finance installation of additional sewage treatment plant and coal mine methane generating facilities for a period of ten years as described in the Request for Exemption. The RIF shall be structured so that KG (or the RIF manager) will monitor performance of the contractor and the installations, track revenues and offsets attributable to RIF-financed systems, and ensure revenues will, for a period of thirty years, be used to finance installation of additional generating equipment. KG (or the RIF manager) shall track the number of installations attributable to the RIF and report regularly to the Council on the performance of the RIF. KG shall establish management or contractual controls of the contractor to provide long-term control of the Fund and the methane project.

14. KG shall commit $0.5 million of the $3.1 million escrow fund into a Revolving Investment Fund for photovoltaics as described in the Request for Exemption. The Fund shall be structured to provide capital to PV companies identified by the SELF. The solar projects shall be in India, Sri Lanka or China unless KG demonstrates to the Council a better location for the PV projects. KG shall structure the Fund so that, as revenues from the systems financed by KG's working capital come into the companies, those revenues will be used to finance installation of additional PV systems. The Fund shall be structured so that SELF (or the Fund manager) shall monitor performance of the companies, track the revenues attributable to Fund-financed systems, and ensure those revenues will be used to finance installation of additional PV systems. SELF (or the Fund manager) shall track the number of PV systems attributable to the RIF and report regularly to KG on the performance of the RIF. KG shall establish management or

contractual controls of the Fund and the PV firms to provide long-term control of the Fund and the PV project.

15. KG shall commit $0.1 million of the $3.1 million escrow fund to fund geothermal heating projects in Klamath Falls, Oregon. KG shall establish a revolving credit fund that will loan money to assist in the hookup of buildings in downtown Klamath Falls to the geothermal heating system. The loans shall be structured for repayment to the fund within three years. Repaid loan amounts shall be used to fund hook up of additional buildings to the geothermal heating system. The fund shall be structured so that KG or the City of Klamath Falls will track revenues and offsets attributable to the fund and ensure that repaid loan amounts are used to hook up additional buildings to the geothermal heating systems.

16. KG shall commit $1.5 million of the $3.1 million to the FRT. KG shall pursue new funding to match these funds on a 3:1 basis.

17. KG shall report as "matching funds" under the FRT proposal only those funds for which the funding entity does not claim, and certifies that it will not claim, offset credit.

18. FRT funds attributed to KG's offset proposal shall be used to plant Site Class II lands for the first 6,250 acres.

19. The Council shall hold in trust for KG all CO_2 credits, including CO_2 credits submitted for inclusion in the Section 1605(b) database, that KG receives from Project offsets. The credits shall be available for use by KG. The credits shall not be sold.

20. The annual water use by the facility shall meet the following requirements:

    a. The facility shall not use more than 129 gallons per minute (gpm) on an annual average basis (8,760 hours) from sources other than Spring Street Waste Water Plant (SSWTP) effluent during all times when the SSWTP is permitted to deliver effluent to the facility. This limit shall not include water supplied as steam to the steam host.

    b. All other water used by the facility shall be effluent from the SSWTP, except when the SSWTP is not allowed to deliver effluent to the facility. During such times the facility shall use only storm water collected on site, or in the event storm water is not available, another temporary source of backup water approved by the Council.

c. Facility wastewater flows shall all be delivered to a sanitary sewer for delivery to the SSWTP. Should the City modify its SSWTP NPDES permit to allow alternative wastewater treatment, disposal, and/or reuse, the wastewater will be returned to the City in compliance with the then prevailing conditions of the City NPDES permit in effect at the time.

21. Before beginning construction, KG shall provide to the Council the plant performance guarantee from the executed contracts for the design and construction of the facility showing a net full power heat rate of no greater than 6795 Btu per kWh (HHV) at average annual conditions with no steam load and using natural gas as the fuel, which shall include liquidated damages provisions adequate to enforce the guarantee. KG shall, as part of the post-construction completion compliance status certification report, provide capacity and heat rate performance test data showing that the nominal electric generating capacity of the energy facility is no more than 318 MW and that the heat rate is no more than 6795 Btu per kWh (HHV) with no steam load and using natural gas as the fuel.

22. Within two months after the completion of the first full year of commercial operation of the energy facility, KG shall report to the Council the energy facility's net full power heat rate as determined by a 100 hour test. Such test will be completed within one year of commercial operation of the energy facility. Based on such test KG shall certify the net full power heat rate of the energy facility. The net full power heat rate shall be measured as the total fuel input divided by the net kWh production over the 100 hour test period, adjusted for difference between the actual ambient site conditions and average annual conditions. If the adjusted net full power new and clean heat rate is greater than the Target Heat Rate of 6,795 Btu (HHB) per kWh with no steam supplied to the steam host and natural gas as the fuel or 7,212 Btu (HHV) per kWh for 200,000 pounds of steam per hour exported and natural gas as the fuel, or a linear interpolation or extrapolation of these values (at average annual ambient conditions based on steam at a pressure of 375 pounds per square inch gauge and a temperature of 455 degrees fahrenheit, in each case measured at the point of interconnection of the energy facility with the steam host), KG shall perform a second 100 our test no later than one year following the completion of the first 100 hours test. If, following the second 100 hour test, the net full power heat rate exceeds the adjusted new full power heat rate just described, then KG shall develop, present to the Council for approval, and implement, a program to offset the incremental CO_2 emissions resulting from the higher heat rate. The higher

heat rate demonstrated by the second 100 hour test shall then become the Target Heat Rate.

23. KG shall, for each calendar year following the year in which the 100 hour test described above is completed, certify to the Council, based on a 100 hour test conducted as described in condition number 22 that the net full power heat rate is no greater than three percent above the heat rate. In the event that KG fails to make such certification, within sixty days following the end of each calendar year, KG shall, at its option, either:

    (1) within 17 months, implement corrective measures to achieve a net full power heat rate of not more than one and one-half percent greater than the heat rate (based upon a 100 hour heat rate test as described in condition number 22); or.

    (2) develop, present to the Council for approval, and implement, a program to offset the incremental CO_2 emissions resulting from the new, higher heat rate in which case the new, higher heat rate shall become the Target Heat Rate.

24. The units shall be fueled solely with natural gas or with synthetic gas with a carbon content per MMBtu no greater than natural gas except that oil may be used for steam and power production for no more than an average of 360 hours per year calculated on a rolling average of the previous five years.