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December 9, 2005

Traci Kirkpatrick, Administrative Law Judge
Administrative Hearings Division
Public Utility Commission of Oregon
550 Capitol Street N.E., Suite 215
Salem, OR 97301-2551
traci.kirkpatrick@state.or.us

Re: *In the Matter of the Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
UM1129
DOJ File NO. 330-020-GN0041-04

Dear Judge Kirkpatrick:

Enclosed is an original and five copies of the testimony of Carel DeWinkel, Jeff Keto, and Phil Carver offered by the Oregon Department of Energy in the above-captioned matter for filing with the Public Utility Commission today.

Sincerely,

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c: Distribution List
Carel DeWinkel, ODOE
Jeff Keto, ODOE
Jeff Carver, ODOE

JLP:tmc/GENO6773

PHASE 1 COMPLIANCE FILING

TESTIMONY OF CAREL DEWINKEL

Q: PLEASE, STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Carel DeWinkel. I am a Senior Policy Analyst with the Oregon Department of Energy. My business address is 625 Marion Street NE, Salem, Oregon 97301.

Q: WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A: I received a graduate degree in Applied Physics from the Delft University of Technology, the Netherlands, in 1972, and a MSc. degree and a Ph.D. degree from the University of Wisconsin in respectively 1974 and 1978. I worked for Wisconsin Power and Light from 1978 to 1989. From 1989 to 1996 I worked for Superconductivity Inc. in Madison, WI, a start-up company that was bought by American Superconductor. I joined the Oregon Department of Energy in April 2001.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I will respond to Issue Number 4 and propose criteria and definitions for determining whether multiple energy projects are in fact a single QF that will have to meet the nameplate criterion of 10 MW or less to be eligible for standard rates and a standard contract.

Q: WHAT IS BASIC ISSUE THAT IS BEING ADDRESSED?

Issue Number 4 states:

Should the Commission adopt criteria for determining whether multiple energy projects are in fact a single Qualifying Facility to protect the intent of Order No. 05-584, which directs that only projects 10 MW and smaller are eligible for standard avoided cost rates and a standard contract? For example, if a 60 MW wind farm is divided into six 10 MW installments in close proximity to one another, all built in the same calendar year, and with underlying ownership structures containing similar persons or entities, should each installment be eligible for standard rates and standard contracts? What criteria determine when a Qualifying Facility is 10 MW or less and eligible for the standard contract when the project/site has multiple generating units?

How do you respond to issue no. 4?

A: As outlined above, a 60 MW wind farm can be divided into six 10 MW installments in close proximity to one another, all built in the same year and owned by the same persons or entities. By doing so, project owners of these six 10 MW projects could argue that they are eligible for the standard rates and standard contracts. Others could argue that this should be considered to be one project larger than 10 MW and therefore ineligible for the standard rates and contracts. ODOE is very concerned about the possibility that disagreements about project size will slow down the growth in QFs with standard rates and contracts. Therefore, precisely stated criteria and definitions are needed.

Q: DO YOU HAVE PROPOSED LANGUAGE THAT ADDRESSES THIS PROBLEM?

A: Yes. In close cooperation with representatives of Idaho Power and Sherman County, I have developed proposed language to determine the nameplate capacity of a QF, which is attached as Attachment 1. The language includes the criteria and definitions for (1) a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Rates, (2) Person(s) or Affiliated Person(s), and (3) Same Site. Furthermore, the proposal includes language that clarifies the inclusion of a Shared Interconnection and states the Commission's role in Dispute Resolution.

Q: DO THE OTHER PARTIES IN THIS PHASE I COMPLIANCE INVESTIGATION FULLY AGREE WITH THIS PROPOSED LANGUAGE?

A: Idaho Power and Sherman County agree with the proposed text. This proposed language has been shared with the other intervenors but I have not received any other comments to date. A final agreement on this issue may be reached at the planned workshop scheduled for December 13th. If so, ODOE will file additional testimony so stating.

Q. WHAT SHOULD THE COMMISSION DO IF THERE IS NO AGREEMENT ON THIS ISSUE?

A. The Commission should adopt the QF definitions in Attachment 1.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Rates:

A Qualifying Facility (either a small power production facility or a cogeneration facility) ("QF") will be eligible to receive the standard rates if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, does not exceed 10 MW.

Definition of Person(s) or Affiliated Person(s):

As used above, the term "same person(s)" or "affiliated person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a "passive investor" if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site:

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for standard rates is sought if they are located within a five-mile radius of any facility or equipment associated with the QF for which qualification for published rates is sought.

Shared Interconnection:

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to the standard rates will not be disqualified by utilizing an interconnection that is shared with other QFs qualifying for standard rates so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved standard contract.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates. Any dispute concerning a QF's entitlement to the standard rates shall be presented to the Commission for resolution.

PHASE I COMPLIANCE FILING

TESTIMONY OF JEFF KETO

Q: PLEASE PROVIDE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Jeff Keto. I am the Loan Manager of the Small Scale Energy Loan Program (Loan Program), Oregon Department of Energy. My business address is 625 Marion St. N.E. Salem, Oregon.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND.

A: I received a BS in Marketing from the University of Oregon in 1977. I worked for US Bank between 1971 and 1993 as a credit examiner, commercial loan officer and district manager. I have worked for the Oregon Department of Energy, Energy Loan Program since 1997. As Loan Manager I oversee loan marketing, underwriting and documentation.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A: The purpose of my testimony is to discuss the following Phase I Compliance issues from the perspective of a lender to QF projects: Issues 5 a, b & c, 6, 8, 13, 14, 21, 20, 33, 35 and 36.

Q: PLEASE DESCRIBE THE BENEFITS TO THE PURCHASING UTILITY OF ODOE'S PARTICIPATION IN A QF PROJECT.

A: If ODOE through its Energy Loan Program (SELP) is financing a project, we believe the utility and ratepayers receive significant protection from our due diligence, our loan conditions and covenants and the fact that we deemed the project worthy of financing. SELP requires project owners to have an equity investment in the project. Our experience is that QFs try to maximize their generation and project revenue. If there is a reduction in generation, SELP has historically worked with QFs to help improve their generation where possible. This includes upgrading controls, transmission or operating characteristics of the project. In the event a borrower does not have the resources or capability to generate sufficient power to meet contracted minimums, they are likely to be delinquent on their loan. In one such a case SELP foreclosed on a project and sold it to an operator who was able to restore generation and operate the facility effectively. SELP believes its involvement in projects helps reduce the risk to utilities and ratepayers. The combined financial risk taken by the QF and SELP is substantial relative to the risk the utility takes with a QF contract.

Q: WHY IS SELP INTERESTED IN THE POWER PURCHASE AGREEMENTS FOR QF FACILITIES?

A: The purpose of the power purchase agreement and its assignment to SELP is to provide a source of revenue sufficient to cover projected operating and maintenance expenses, debt service and a reserve, with minimal risk of disruption of that revenue stream. This income stream acts as the primary security for the loan. The power purchase agreement needs to be reviewed in its entirety for acceptance. The circumstances that make a provision acceptable in one transaction and not in another can't be cited inclusively. In general, the larger the amount of equity capital and the lower the amount of financing needed for a project, the more SELP has the ability to accept higher risk in the power purchase agreement and still finance the project. Loans that are supported by a strong financial balance sheet that includes additional revenue streams may also allow acceptance of more risk in the power purchase agreement while still being acceptable for financing. However, most of the community scale projects SELP has reviewed, have very little financial reserves and thus require a power purchase agreement with limited risk in order to finance their project. The proposed decreasing power rates over the first five years delivers sufficient risk in the financing that the probability of default and payment of damages must be very small in order to accommodate financing.

Q: WHAT IS YOUR GENERAL UNDERSTANDING OF ORDER NO. 05-584 REGARDING CREDITWORTHINESS?

A: ODOE believes, per Order # 05-584, § L(2)(c), that a QF has the option of meeting creditworthiness by making the following representations and warranties: "that the QF has good credit, including that it is current on existing debt obligations and has not been a debtor in a bankruptcy proceeding within the preceding two years." ODOE understands the Order to mean that a QF can demonstrate creditworthiness by making this set of representations and warranties without any other action or representation required.

The Order further states "we adopt Staff's proposal that requires a QF unable to satisfy credit rating requirements to provide a reasonable amount of default security by one of the following means, selected at the QF's discretion: senior lien, step-in-rights, a cash escrow or a line (letter) of credit." ODOE interprets this to mean that a utility can accept a QF as creditworthy if it has a satisfactory credit rating (long-term debt rating by Moody's or Standard and Poor's) and thus not require the QF to provide default security. ODOE believes that this does not mean that a long-term debt rating is required in addition to making the prior set of representations and warranties in order to establish creditworthiness. Requiring a long-term credit rating, which the majority of QFs would not possess, or any other condition, other than making the above set of representations and warranties, does not comply with the Order.

Q: IN GENERAL, ISSUE 5.a. ADDRESSES THE REASONABLENESS OF SECURITY PROVISIONS. HOW DO YOU RESPOND TO ISSUE 5.a.i.?

A: The filed utility contracts include requirements for creditworthiness beyond a QF making the above set of representations and warranties. Idaho Power (IP) (§ 4.1.6) states that the specified security requirements are "at a minimum," which does not bring transparency to the contract and leaves IP to add additional requirements as they see fit or to require the posting of security. PacifiCorp (§ 3.2.7) requires QFs over 3MW to have a long-term debt rating in addition to making the stated representations and warranties or post security. As stated above, ODOE believes these or similar provisions should not be allowed and are in violation of the Order.

PGE requires a QF to additionally warrant that it will continue to be current on its obligation throughout the term of the contract (§ 3.1.4). SELP interprets this to mean that if the QF was delinquent on its loan to SELP, even if we had a structured workout to bring the borrower current, PGE could declare an event of default and require default security. These provisions could lead to default without the ability of the QF to cure the default. It is unlikely the QF would have resources to meet the default security. SELP assumes that the only viable security option a QF has under such a situation is to establish an escrow account. Most likely the QF could not qualify for a letter of credit, could not give a senior lien on the project and could not give step-in-rights if it requires posting a letter of credit or similar instrument as PacifiCorp does (§ 10.5). This provision in the PGE contract would generally prohibit SELP from financing the project.

Q: HOW DO YOU RESPOND TO ISSUE 5.a.iii.?

A: If a QF is not able to make the representations and warranties to meet creditworthiness, as stated above, the Order provides that a QF can provide one of four security options (Order # 05-584, § L(2)(c)). These are: senior lien, step-in-rights, a cash escrow or a line (letter) of credit. ODOE believes that IP and PGE should define these options to provide contract transparency, much as PacifiCorp has.

Q: HOW DO YOU RESPOND TO ISSUE 5.a.ii.?

A: PacifiCorp's contract (§ 10.5) requires a letter of credit for environmental remediation in the event of QF default if the QF selects either the senior lien or step-in rights security option. ODOE believes that many renewable generation projects have little environmental remediation potential and that asking all those who choose step-in rights or a senior lien to provide a letter of credit would unduly burden them at minimal reduction in risk to ratepayers. To pose a risk to the utility and ratepayers, a QF would need to default, there would need to be significant environmental remediation required and market energy prices would need to be above contract prices. In the rare event all these condition occur and a utility chooses not to step-in they can always litigate against a QF to seek damages. ODOE believes it is not correct to ask all QFs that choose step-in rights or offer a senior lien to pay the full amount to cover a risk that will be a rare occurance by a very small percentage of QFs.

Because of the expense and the inability of most small QFs to obtain a letter of credit, ODOE believes a letter of credit should not be required for QF projects on greenfield sites. For a generation project at an industrial or brownfield site the host company should be given the option to assume this financial responsibility in lieu of a letter of credit. If the Commission approves the utilities' use of a letter of credit in the event of step-in-rights or senior lien, the Commission should qualify that a letter of credit should only be needed in circumstances where environmental remediation is a clear documented risk and the amount of the letter of credit should not exceed the documented potential risk.

Q: IN GENERAL, ISSUE 5.b. ADDRESSES THE REASONABLENESS OF THE DEFAULT AND TERMINATION PROVISIONS. HOW DO YOU RESPOND TO ISSUE 5.b.iii.?

A: In ODOE's experience financing QF projects it is difficult for many QFs to accurately predict the minimum availability of natural motive resource and thus minimum delivered power for any specific week, month or even year over that life of a twenty year contract. In our experience actual available resources do vary below those estimated for a given period during the course of a twenty-year contract. In developing projects, the available historical resource data can vary from 10 to30 years of water flow, a year or two of wind data, or the assumed availability of biomass from forest lands. Severe weather events like forest fires, severe storms, floods and droughts are unpredictable. Loan underwriting is based on a predicted long-term average availability of a resource, but variations from one period to the next are expected. Because of the variation in resource availability and the need for flexibility, ODOE loan documents do not include lack of motive force as a default. ODOE works with its borrowers in times of low available resource, without adding loan penalties, because we believe the resource will return and the project will regain generation and revenue in future periods. Adding penalties at times of low resource availability can be a financial disaster for a project.

A QF standard contract needs to accommodate variations in delivered power according to the type of resource and the variability of that resource over time. One primary risk to a QF in meeting any contracted minimum delivered power is the lack of natural motive resource due to catastrophic weather events (forest fire, severe draught, severe storm). ODOE recommends that this risk can best be mitigated by including catastrophic weather related events in force majeure, which is not the case in any of the three filed contracts. A QF should not be in default or owe damages because of unusual or severe weather conditions.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.i.?

A: The Order states “we conclude that intermittent and firm resources should be valued equally” (§ C(3)), and “It is inappropriate to request that standard contracts be subject to potential negotiations to address project-specific characteristics” (§ I(2)). However, each of the filed contracts provides space for the QF to fill in an amount of delivered energy on a monthly or annual basis, which if not delivered will result in default and penalties. ODOE is concerned that settting the delivered amounts in the contract will be subject to negotiations because a QF will want to use a very low number to avoid default and the possible payment of damages while the utility will want a higher number. To avoid potential negotiations ODOE recommends the standard contracts state a minimum amount of delivered power based on the type of resource. ODOE recommends setting annual minimum power delivery based on the following capacity factors of nameplate ratings: 5 percent for solar, 10 percent for hydro and wind, 20 percent for geothermal, biomass or natural gas fired cogeneration. The percentage should be adjusted by the percentage of power a QF intends to use on site. These pre-set minimums need to accommodate a wide variety of generating projects including the small farm-scale facilities. If the contract requires minimum delivered power that is likely to put a QF in default or require payment of damages, financing the project will be very difficult if not impossible.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.xi?

A: PacifiCorp's contract provides that in the event of termination a QF may not sign a new contract to sell power until after the contract expiration date (§ 11.3.2). ODOE believes this is not in the spirit of the Order and may not be allowed under PURPA. Such a restriction could preclude ODOE from foreclosing and selling the project and thus would render the project not be acceptable for financing. ODOE requires the right and opportunity to foreclose on a facility and sell it to a new owner with the original power purchase agreement remaining in effect. ODOE recommends that the Commission not allow standard contracts to prohibit a QF from making future sales to the utility if a contract default or termination occurs.

Q: HOW DO YOU RESPOND TO ISSUE 5.b.xiii.?

A: ODOE believes it is reasonable for the utilities to request the QF provide anticipated power delivery figures for planning purposes. The Net Energy Amount in Idaho Power's contract (§ 1.12 and 6.2), which is the amount of power a QF intends to deliver to IP, is also the amount that could result in penalties if not delivered. ODOE believes that the IP contract should include the monthly anticipated power delivery for informational purposes but should not use these amounts to calculate any potential penalties. Penalties should be based on a separate minimum delivered annual capacity figure the QF fills in or the capacity factors as discussed above.

Q: HOW DO YOU RESPOND TO ISSUE 5.b. AS THE ISSUE RELATES TO DAMAGES AND TERMINATION OF THE QF CONTRACT IN GENERAL?

A: ODOE recognizes that the Commission provided that a QF may owe damages if the facility does not meet the contracted commercial operations date or deliver the minimum amount of contracted power (§ L(2)(c), L(3)(c)). Any damages to cover utility costs are to be repaid by reducing future payments to the QF.

ODOE believes the Commission intended these damages to adequately protect the utility and ratepayers but also allow for the continued operation of the QF generating facility. The filed contracts allow for termination for not meeting the scheduled commercial operations date or not delivering the minimum required power in any given period. This should not be allowed. A lender needs the time to work with a borrower to cure defaults and correct any project construction or operational problems. A lender also needs the time to foreclose on a project, make improvements or repairs, and resell it with a valid power purchase agreement.

Termination for late start up or under-delivery of power will make many QF projects unfinancable by SELP. If termination is allowed for under-delivery of power, it should be allowed only in the most egregious cases that do not involve that lack of motive force, and the contracts should allow the QF to make repairs and correct operational problems or allow the lender to take legal action and facilitate renewed generation within a commercially reasonable time frame. The time needed to accomplish these actions could be more than one year if parts, contractors or transportation are difficult to obtain. If the Commission allows termination for under-delivery in egregious cases, SELP recommends that the contracts allow two years to cure the lack of power delivery before termination is an option.

Q: HOW DO YOU RESPOND TO ISSUE 5.c. AS THE ISSUE RELATES TO THE CALCULATION AND LEVEL OF DAMAGES IN GENERAL?

A: As stated above, the Order provides for payment of damages by the reduction of future contract payments. PacifiCorp's contract states that it will work with the QF to limit the reduction in payments to provide for continued facility operation and payment of debt (§ 11.4.2). ODOE recommends that similar language be inserted in IP and PGE standard contracts. If contract penalties can reduce revenue below that which is needed for continued facility operation and payment of debt service, such penalties will reduce the amount of debt any project can obtain and require additional equity that simply is not available for many locally-owned QF projects. In the Order the Commission indicates that "future payments after the default period ends shall be commensurately reduced for a reasonable period of time" (§ L(2)(c).

Q: HOW DO YOU RESPOND TO **ISSUE 6, WHICH PROVIDES: Should tariffs for Qualifying Facilities include a detailed list of procedures, including timelines, to comply with the Commission's directive that such tariffs contain "full details about the process to enter into a standard contract or a negotiated contract," per Order No. 05-584 at 59? If yes, which procedures and timelines should be included at a minimum, and what timelines are appropriate?**

A: ODOE recommends that the tariffs provide that the utility will review standard contracts submitted by a QF and sign or provide the reason for not signing within 30 days of the date submitted.

Q: HOW DO YOU RESPOND TO ISSUE 8, WHICH PROVIDES: Should increased Qualifying Facility output resulting from changes in operation of generating equipment — for example, improving its efficiency or operating at a higher power factor — qualify for the full avoided cost prices in the tariff as of the effective date of the agreement? Should increased generation resulting from efficiency improvements that increase the project's output above the nameplate rating specified in the contract be entitled to full avoided cost prices, so long as the project's nameplate rating remains at or below 10 MW? If so, should the increased generation be priced at the full avoided cost in the tariff as of the effective date of the agreement or as of the date of the improvement? Can Seller change the generator nameplate rating if equipment replacement is necessary?

A: The standard contract should not penalize or prohibit QF projects from making efficiency improvement to their generating facility. The standard tariff should also recognize that a QF may want to increase the net generation of a project. At the same time, ODOE recognizes that the standard contract is limited to 10MW nameplate capacity and that adding any additional generation will require a review of interconnect and transmission availability. In addition, the economics of power rates and the cost of generation will likely vary over time.

To accommodate improvements in efficiency and the possible increase in generation at a QF site, ODOE suggests that the original contract payment terms should apply to the facility generation up to original nameplate rating. If efficiency improvements or additional generation capacity is installed, a QF should be paid at the original contract rates up to the original nameplate rating, Any increase of nameplate rating up to 10MW should be paid at the avoided cost rates in effect as of the date of the improvement. This provides the QF with capacity payments for any additional generation but only up to the facility's nameplate rating.

Q: HOW DO YOU RESPOND TO ISSUE 13, WHICH PROVIDES: Can Seller choose to service some or all of its own load that is not plant parasitic load to determine Net Output?

A: A QF should be able to service part or all of its own load and enter into a standard contract for the net generation provided the nameplate capacity is no greater than 10MW. Allowing a QF to supply their own load as part of Net Output provides a good incentive to some QFs to embark on the complex and costly task of developing a generation resource.

Q: HOW DO YOU RESPOND TO ISSUE 14, WHICH PROVIDES: If a utility and a Qualifying Facility Seller under 10 MW mutually agree to change a few terms of the standard contract for a facility but still use the applicable standard tariff, is this arrangement considered a PURPA contract in future rate making proceedings?

A: ODOE supports the ability of a QF and utility to make mutually agreeable changes to a standard contract form, while still using the published tariff, as this helps facilitate the development of additional generation resources. Mutually agreeable changes will protect ratepayers because of utility review and benefit ratepayers from a new energy resource. As the utility would still be obligated to purchase this power under PURPA, the modified contract should enjoy whatever protections a PURPA contracts offers.

Q: HOW DO YOU RESPOND TO ISSUE 21, WHICH PROVIDES:

If the Commission's decision in AR 495 allows, should standard contracts contain a waiver of claim to ownership of environmental attributes of delivered power as provided in § 8.1 of Idaho Power's contract?

A: The standard contracts should specify the ownership of environmental attributes of the QF power (a.k.a. renewable energy certificates or RECs). This should conform to the Commission's decision in AR 495. If the Commission decides the RECs belong to the utility, the avoided cost payments should reflect the market value of the RECs**.**

Q: HOW DO YOU RESPOND TO ISSUE 30, WHICH PROVIDES: Are prohibitions against any liens or encumbrances on the project other than for third party financing in § 3.1.5 of PGE's contract too restrictive?

A: This provision may preclude or reduce the availability of financing. As a lender, we would ask that an exception be included in the contract to allow for statutory liens. Contractors, material suppliers and others have the authority under law to file liens, which may occur during construction, maintenance or upgrade of a generating facility. The filing of this type of lien can't be prohibited. We would not want the filing to automatically trigger a default in the contract and subsequent penalties or termination. An exception for statutory liens should also recognize that the project owner has the right to contest a lien in good faith, which may involve significant time to clear the lien.

For the Commission's reference, here is the current language in ODOE loan agreements:

> "Permitted Liens" means, with respect to the Collateral, in addition to any liens and security interests created by the Security Documents:
>
> (a) Any liens for taxes, assessments, levies, fees,

water and sewer rents, and other governmental and similar charges and any liens of mechanics, materialmen, laborers, suppliers or vendors for work or services performed or materials furnished in connection with the Premises or the Project, which are not due and payable or which are not delinquent or the amount or validity of which are being contested in good faith and execution thereon is stayed or, with respect to liens of mechanics, materialmen, laborers, suppliers or vendors, have been due for less than 60 days;

(b) Easements, rights-of-way, servitudes, restrictions, oil, gas or other mineral reservations and other minor defects, encumbrances and other matters affecting title to the Premises, including without limitation, rights reserved to or vested in any municipality or public authority to control or regulate the Premises or to use such Premises in any manner, to the extent set forth in Preliminary Title Report, dated __________, ________ issued by Title Company.

Q: HOW DO YOU RESPOND TO ISSUE 33, WHICH PROVIDES:

Is it reasonable for Idaho Power to require in § 3.3 that a hydroelectric Qualifying Facility warrant that it has a FERC license at the time of execution of the agreement, rather than warrant it will have a FERC license prior to the first operation date?

A: SELP supports requiring a FERC license at the date of initial operations. Based on a limited review of older hydro projects SELP financed, SELP normally required a FERC license at the time of loan closing and first loan disbursement. SELP staff believes that loan advances were made on at least one hydro project prior to the facility receiving its FERC license. In order to advance funds SELP would require a signed PPA. Allowing a QF to wait until first operations for a FERC license adds flexibility in project development. The standard contracts should require hydro QFs to have applied for a FERC license but should not require the QF to have a license at the time the standard contract is signed. Requiring a license to obtain a standard contract may reduce the viability of some hydro QF projects with negligible risk reduction for utilities and ratepayers.

Q: HOW DO YOU RESPOND TO ISSUE 35, WHICH PROVIDES: 'In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required (relating to standard contract only).

A: In earlier testimony ODOE stated that default security may be specific to project type, but should be limited to around 2% of project capital costs. Of the forms of default security a QF can choose from (senior lien, step-in-rights, a cash escrow or a line (letter) of credit), a senior lien would not be available if the project is financed. A letter of credit would likely not be available for most locally-owned projects, because they would not have security to pledge to a bank that provides the letter of credit. A cash escrow deposit may be the only available security option, and the amount of the escrow deposit will probably be paid from additional equity from the project owners. Financing will already be maximized based on the projected project cash flow. This means the QF must find equity to cover any additional project costs. Equity is in short supply for most locally-owned projects. We arrived at the limit of 2% of project capital costs using the following example that represents a locally owned project that SELP would like to finance. To look at the cost of an escrow deposit in terms of a potential project, ODOE has reviewed a 1.5 MW QF project that costs around $2.4 million to construct. An ODOE loan, an Oregon Business Energy Tax Credit pass-through and tax-equity contribution based on federal tax credits is projected to provide the majority of the project funding while $100,000 to $200,000 is provided by the local land owners. This project is based on some added revenue from the Energy Trust. A 2% increase in project cost for an escrow default security account would be around $50,000. This would be a significant amount for the property owners to raise. A larger sum would likely make the project unworkable. Higher equipment prices are increasing the cost of generating projects. As a result the Energy Trust is being asked to contribute more. I suspect the Energy Trust would not increase their contribution to a project just to cover a default security deposit. In this example, $50,000 represents roughly three months of projected average project power sales revenue.

Q: HOW DO YOU RESPOND TO ISSUE 36, WHICH PROVIDES:

Cap on amount of default losses that can be recouped, pursuant to future QF contract payment reductions.

A: ODOE believes a reasonable cap on the amount of losses that can be recouped by the utility for an individual event of default is the contract value of the contracted minimum power delivery during the default period.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

PHASE I COMPLIANCE FILING

TESTIMONY OF PHIL CARVER

Q: PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A: My name is Philip H. Carver. I am a Senior Policy Analyst with the Oregon Department of Energy. My business address is 625 Marion St. N.E., Salem, Oregon 97301.

Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF YOUR EDUCATION AND EMPLOYMENT BACKGROUND

A: I received a Ph.D. in utility and natural resource economics from the Johns Hopkins University in 1978. I have worked for the Oregon Department of Energy (formerly the Oregon Office of Energy) continuously since 1980. In that time, I have testified before the Oregon Public Utility Commission (OPUC) on economic, forecasting, planning and rate design issues in several dockets.

Q: WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS CASE?

A: My testimony will discuss issue No.15, and other issues related to gas price forecasts for avoided cost determinations.

Q: issue 15 provides:

15. Are the natural gas price forecasts that Portland General Electric and PacifiCorp (PAC) used for determining avoided costs reasonable? [Staff, ICNU]

HOW DO YOU RESPOND TO ISSUE 15?

A: The natural gas price forecasts the Portland General Electric and PacifiCorp (PAC) have used for determining avoided costs are not reasonable. Even if they were reasonable at the time, natural gas prices have shifted significantly since July of 2005. Much of the change occurred before August 30 so it is not related to damage to the Gulf Coast gas infrastructure from hurricanes Katrina and Rita. The graph (document "HHub 12 months 11-14-05") shows that for the 8 months before mid July, Henry Hub spot prices ranged between $8 and $6 per MMBtu. Since August 1st , prices have ranged from $8 to $14. Annual average Henry Hub forward prices for 2006-to-2010 on the NYMEX on Nov. 14, 2005 were $10.61, $9.35, $8.28, $7.54 and $7.01 respectively. (*See* Attachment 1.) These values are widely different than the gas prices that PGE and PAC used for 2008-to-2010, even accounting for the negative basis differentials for western gas hubs. PGE's avoided cost filing has nominal gas prices of $4.27 and $3.67 for Sumas, for 2009 and 2010 respectively (Table 14). These forecasts were inconsistent with actual NYMEX futures prices for Henry Hub on the day they were made. Attachment 2 shows the NYMEX download that PGE conducted on July 6, 2005. This shows that annual average Henry Hub futures prices for 2009 and 2010 of $7.27 and $6.98 per MMBtu on that day. The same page shows the PGE's Sumas price forecasts for 2009 and 2010 of $4.27 and $3.67 per MMBtu. These prices imply a negative basis differential for Sumas of $3.00 and $3.31. These are ridiculous basis differentials. Although large basis differentials can occur for a single month or even a year due to specific regional problems, such as the recent hurricanes, no reputable forecast would predict long-run Sumas-Henry Hub basis differential this large. The Northwest Power and conservation Council (NWPCC) had negative basis differentials for Sumas that ranged from $0.51 to $0.69 for the Medium and High gas cases of its 5th Power Plan published in May of this year.

PGE and PacifiCorp might claim that their consultants' forecasts are somehow better than using NYMEX futures prices. While it is certainly possible that a single forecast might outperform a single day's the NYMEX futures values as a predictor, there is no reason to expect this over the long term. For the last several years, these "expert" forecasts have been staggeringly wrong. In contrast, note that over the 4 months from July to November, the NYMEX future price for 2010 moved up only $0.03 (from $6.98 on July 6, 2005 to $7.01 on November 14, 2005). NYMEX quotes on December 6 for 2010 were about $0.20-$0.25 higher than on November 14. This is excellent stable behavior for a long-term forecast during a period of strong short-term market fluctuations. The 2010 market participants were not panicked by the recent short-term supply disruptions from Gulf Coast hurricanes. This corresponds with economic fundamentals. The residual impact of these 2005 short-term disruptions will likely be completely dissipated by 2010.

Although PacifiCorp's forecasts are closer to reality, they also diverge from NYMEX prices. The PAC filed avoided costs have Opal gas prices of $5.90 to $5.16 for 2008 to 2010. For the Medium and High NWPCC cases the Opal negative differentials from Henry Hub ranged from $0.66 to $0.94. These are similar to the basis differentials used by PAC. Applying the larger NWPCC differential ($0.94, 2000$) to the NYMEX 2010 future price of $7.01 would yield an Opal 2010 price of $5.81 in 2010$ (escalating the $0.94 NWPPC Opal basis differential to 2010 at 2.5 percent inflation yields an Opal basis differential of $1.20 in 2010 dollars). Although the difference between the NYMEX derived 2010 regional hub price and the price used in PacifiCorp's avoided cost is not as dramatic as in the case of PGE, it is still significant and should be corrected for the compliance filing that follows this Phase I OPUC order.

For example, the September 30, 2005 update to the publicly available forecast (Attachment 5) was substantially different from the PacifiCorp Henry Hub NYMEX 2010 price. PacifiCorp forecasted $6 per MMBtu for Henry Hub for 2010 when NYMEX had been around $7 since July.

Forward power markets are strongly affected by forward gas prices so the wholesale power prices used in the avoided costs need to be revised as well.

Q: WHAT SHOULD THE COMMISSION TELL THE UTILITIES TO DO WHEN SUBMITTING NEW AVOIDED COSTS?

A: The process of using actual forward prices to estimate wholesale power prices does not need adjustment. The numbers just need to be updated to the latest forward electric prices. For natural gas prices, utilities should use the NYMEX forward curves updated at the latest available date with Commission specified basis differentials for regional gas hubs versus Henry Hub.

All of the gas price forecasts used by utilities since 2001 have been wildly inaccurate, especially the Cambridge Energy Resource Associates (CERA) forecasts used by PGE. Forward prices on NYMEX represent real hedges that market participant can actually buy. They are the average of market participants' expectations. NYMEX prices, to the extent available, are a superior price forecast to numbers made up by consultants. NYMEX market participant subscribe to numerous forecasts and apply their own unique expertise and risk analysis. These futures prices are now available through 2011.

Q: WHAT BASIS DIFFERENTIAL FOR HUB PRICES SHOULD THE COMMISSION SPECIFY FOR THE NEXT COMPLIANCE FILING?

A: The Commission should specify the High Case basis differentials from the NWPCC 5th Power Plan. These would set Sumas, Opal and AECO hub prices below Henry Hub by \$0.69, \$0.94 and \$0.78, respectively. These are real 2000\$ values and would be escalated at nominal inflation. Note that a higher basis differential yields lower costs to customers than the Medium case differential. The High case differentials are justified because it is now clear that the NWPCC Medium case gas price forecast and the associated differentials are inconsistent with what we see in the futures markets. The NWPCC plans to adjust their basis differentials in late 2006. The avoided cost filings in 2007 or 2008 could use these updated forecasts of basis differentials. If utilities want to propose different fixed annual basis differentials than the NWPCC values or if they want to propose fixed differentials that vary by month, ODOE is open to further discussions.

In any case, the Commission should require that the latest Henry Hub NYMEX values be used and that regional hub prices be based on fixed Commission set basis differential for Oregon avoided cost filings.

Q: WHAT ABOUT HENRY HUB GAS PRICES BEYOND 2010, THE FARTHEST FORWARD PRICE ON NYMEX?

A: Gas prices would just be escalated at nominal inflation. Five years out is far enough to eliminate any short-term price fluctuations. Any adjustment beyond nominal inflation would be wildly speculative.

Flat real prices of around \$7 after 2011 are a reasonable base for long-term fixed cost avoided cost contracts. This would correspond to a light-sweet crude (WTI) price of roughly \$50 per barrel, when Henry Hub gas trades a dollar or two per MMBtu below oil, as has been typical until the disruption by recent hurricanes. Long term, world crude oil prices will drive delivered U.S. Liquefied Natural Gas (LNG) prices. There is wide substitutability between natural gas and oil in world markets and exporting gas countries can unilaterally alter contract prices. Fixed price LNG contracts, even if available, will offer little certainty. Owners of gas liquefaction facilities cannot walk away when exporting counties abrogate their contracts. Delivered LNG prices are the incremental U.S. source and thus will drive U.S. natural gas prices.

There is huge uncertainty on natural gas and oil prices as we approach the year of world peak production of light crude oil, which may occur in a couple of years. Even the optimists (e.g., CERA) see the peak as no more that a couple of decades away. See R. L. Hirsch "The Inevitable Peaking of world Oil Production" from the October 2005 issue of the Atlantic Council Bulletin (Attachment 3). When (not if) world oil production peaks, world oil prices will likely spike to $100 a barrel or above. This is because the investments to bring oil prices down to the $50 level will take decades to complete, and will not begin until after prices spike. Even before oil reservoirs dictate declining production, a disruption in a major oil exporting country could drive the oil price to $100 a barrel. The corresponding natural gas price would be about $14 per MMBtu. These risks are real and balance the optimistic forecasts of many consultants.

As examples of the problems of allowing utilities to pick consultants as a way to pick their forecast, PGE and PacifCorp used consultants with forecasts below NYMEX futures prices. While these forecasts of oil and natural gas prices are possible, they are not likely. See Ron Cooke "Oil Depletion? It's All In The Assumptions" (August 2005) (Attachment 4).

The use of a Henry Hub price of $7 per MMBtu gas (2010$) for the years after 2010 represents a responsible middle ground between the optimists and the pessimists on world energy prices. Given the risks of rapidly escalating energy prices if world oil production peaks, locking in this price now from standard QF contracts represents a very good deal for utility customers.

Q: HOW DO YOU RESPOND TO ISSUE 16:

16: What are the appropriate natural gas hubs? [ICNU]

A: The two hubs used by PGE (Sumas and AECO) and the Opal Hub for PAC are acceptable for the updated filing.

Q: HOW DO YOU RESPOND TO ISSUE 17:

17. Are the forward price projections that Portland General Electric and PacifiCorp used to determine the on-peak and off-peak avoided costs during their projected resource sufficiency periods reasonable? [Staff]

A: Yes, as long as they are updated and refiled.

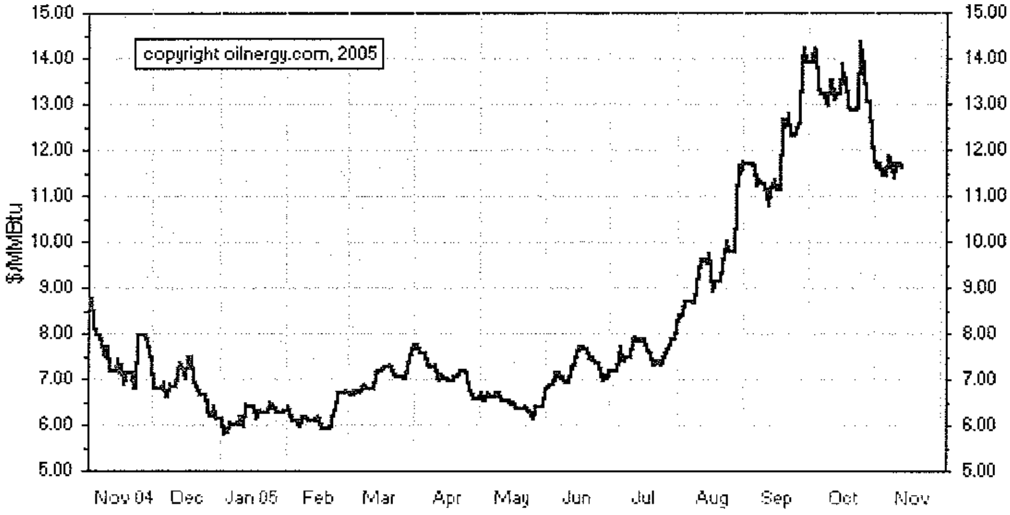
Q: DOES ODOE HAVE ANY COMMENT ON THE ISSUES RELATED TO THE RESOURCE SUFFICIENCY/DEFICIENCY PERIOD?

A: No.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

NYMEX Henry-Hub Natural Gas - 12 previous months



ATTACHMENT 1
Page 1 of 2

NYMEX Henry Hub Natural Gas Futures Prices

Month	Year	Nominal $/MMBtu	Most Recent Settle Date	EDT
Jan	2006	12.236	11/14/2005	12:38:03
Feb	2006	12.261	11/14/2005	12:34:10
Mar	2006	12.031	11/14/2005	12:32:57
April	2006	9.991	11/14/2005	12:34:19
May	2006	9.831	11/14/2005	11:52:21
June	2006	9.861	11/14/2005	11:35:58
July	2006	9.908	11/14/2005	11:45:18
Aug	2006	9.948	11/14/2005	12:07:40
Sep	2006	9.938	11/14/2005	11:19:26
Oct	2006	9.986	11/14/2005	11:24:47
Nov	2006	10.451	11/14/2005	11:21:44
Dec	2006	10.916	11/14/2005	12:34:06
Ann. Avg		**$ 10.61**		
Jan	2007	11.296	11/14/2005	12:16:28
Feb	2007	11.231	11/14/2005	11:43:43
Mar	2007	10.926	11/14/2005	9:30:40
April	2007	8.701	11/14/2005	10:19:29
May	2007	8.488	11/14/2005	10:12:58
June	2007	8.523	11/14/2005	9:30:40
July	2007	8.558	11/14/2005	9:30:40
Aug	2007	8.598	11/14/2005	9:30:40
Sep	2007	8.578	11/14/2005	9:30:40
Oct	2007	8.618	11/14/2005	9:30:40
Nov	2007	9.093	11/14/2005	9:30:40
Dec	2007	9.563	11/14/2005	10:56:02
Ann. Avg		**$ 9.35**		
Jan	2008	9.933	11/14/2005	9:30:40
Feb	2008	9.863	11/14/2005	9:30:40
Mar	2008	9.548	11/14/2005	9:30:40
April	2008	7.708	11/11/2005	15:18:27
May	2008	7.503	11/11/2005	15:18:27
June	2008	7.553	11/11/2005	15:18:27
July	2008	7.598	11/11/2005	15:18:27
Aug	2008	7.638	11/14/2005	12:00:53
Sep	2008	7.618	11/14/2005	12:00:58
Oct	2008	7.658	11/11/2005	15:18:27
Nov	2008	8.148	11/11/2005	15:18:27
Dec	2008	8.633	11/14/2005	10:04:37
Ann. Avg		**$ 8.28**		
Jan	2009	9.038	11/11/2005	15:18:27
Feb	2009	8.958	11/11/2005	15:18:27
Mar	2009	8.658	11/11/2005	15:18:27
April	2009	7.008	11/11/2005	15:18:27
May	2009	6.798	11/11/2005	15:18:27
June	2009	6.848	11/11/2005	15:18:27
July	2009	6.898	11/11/2005	15:18:27
Aug	2009	6.948	11/11/2005	15:18:27
Sep	2009	6.933	11/11/2005	15:18:27
Oct	2009	6.973	11/11/2005	15:18:27
Nov	2009	7.468	11/11/2005	15:18:27
Dec	2009	7.948	11/14/2005	10:04:31
Ann. Avg		**$ 7.54**		
Jan	2010	8.353	11/11/2005	15:18:27
Feb	2010	8.263	11/11/2005	15:18:27
Mar	2010	7.963	11/11/2005	15:18:27
April	2010	6.543	11/11/2005	15:18:27
May	2010	6.343	11/14/2005	10:09:56
June	2010	6.378	11/11/2005	15:18:27
July	2010	6.418	11/14/2005	9:30:40
Aug	2010	6.458	11/11/2005	15:18:27
Sep	2010	6.438	11/11/2005	15:18:27
Oct	2010	6.483	11/11/2005	15:18:27
Nov	2010	6.978	11/11/2005	15:18:27
Dec	2010	7.473	11/14/2005	10:05:24
Ann. Avg		**$ 7.01**		

PORTLAND GENERAL ELECTRIC COMPANY
2005 Avoided Cost Filing
Natural Gas Price Forecasts

[From PGE Spreadsheet DR_001_Attachment_A, "Gas Price Forecast" Tab
NYMEX data available from nymex.com web site.
Sumas prices the same as Table 14 in PGE filed avoided costs]

Assumptions

Close of day 7-6-05 NYMEX

	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
2006	9.20	9.21	9.08	8.03	7.88	7.92	7.97	8.01	8.00	8.03	8.38	8.71	8.37
2007	8.94	8.93	8.80	7.62	7.50	7.54	7.58	7.60	7.59	7.61	7.95	8.26	7.99
2008	8.48	8.47	8.33	7.25	7.13	7.17	7.21	7.24	7.22	7.25	7.58	7.89	7.60
2009	8.11	8.10	7.96	6.94	6.81	6.85	6.88	6.92	6.90	6.92	7.25	7.57	7.27
2010	7.79	7.77	7.62	6.67	6.54	6.57	6.61	6.64	6.63	6.65	6.98	7.30	6.98

SOURCE: NYMEX web page download

Long-term Inflation Rate	2.50%
Heat Rate	6776
Losses	1.9%

SUMAS

	Flat Annual Price (nominal)	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.	CERA Rearview Mirror
2009	**4.27**	4.76	4.76	4.67	4.07	4.00	4.02	4.04	4.06	4.05	4.07	4.26	4.44	4.27	4.27
2010	**3.67**	4.10	4.09	4.01	3.51	3.44	3.46	3.48	3.49	3.49	3.50	3.67	3.84	3.67	3.67
2011	**4.33**	4.83	4.82	4.73	4.14	4.06	4.08	4.10	4.12	4.11	4.13	4.33	4.53	4.33	4.33
2012	**4.59**	5.12	5.11	5.02	4.39	4.30	4.33	4.35	4.37	4.36	4.38	4.59	4.80	4.59	4.59
2013	**5.24**	5.84	5.83	5.72	5.00	4.90	4.93	4.96	4.98	4.97	4.99	5.24	5.47	5.24	5.24
2014	**5.83**	6.50	6.49	6.36	5.57	5.46	5.49	5.52	5.54	5.53	5.55	5.83	6.09	5.83	5.83
2015	**5.87**	6.55	6.54	6.41	5.61	5.50	5.53	5.56	5.59	5.58	5.60	5.87	6.14	5.87	5.87
2016	**4.70**	5.24	5.23	5.13	4.49	4.40	4.42	4.45	4.47	4.46	4.48	4.70	4.91	4.70	4.70
2017	**5.03**	5.61	5.60	5.49	4.80	4.71	4.73	4.76	4.78	4.77	4.79	5.03	5.26	5.03	5.03
2018	**5.88**	6.56	6.55	6.42	5.62	5.51	5.54	5.57	5.59	5.58	5.60	5.88	6.15	5.88	5.88
2019	**6.78**	7.57	7.55	7.40	6.48	6.35	6.38	6.42	6.45	6.44	6.46	6.78	7.09	6.78	6.78
2020	**7.35**	8.20	8.18	8.02	7.02	6.88	6.92	6.95	6.99	6.97	7.00	7.35	7.68	7.35	7.35
2021	**7.53**	8.40	8.38	8.22	7.19	7.05	7.09	7.13	7.16	7.15	7.17	7.53	7.87	7.53	7.53
2022	**7.72**	8.61	8.59	8.43	7.37	7.23	7.27	7.31	7.34	7.33	7.35	7.72	8.07	7.72	7.72
2023	**7.91**	8.83	8.81	8.64	7.56	7.41	7.45	7.49	7.52	7.51	7.54	7.91	8.27	7.91	7.91
2024	**8.11**	9.05	9.03	8.85	7.75	7.59	7.63	7.68	7.71	7.70	7.73	8.11	8.48	8.11	8.11
2025	**8.31**	9.27	9.25	9.08	7.94	7.78	7.83	7.87	7.90	7.89	7.92	8.31	8.69	8.31	8.31

NYMEX download
7/6/2005

Jan-06	9.202
Feb-06	9.214
Mar-06	9.082
Apr-06	8.027
May-06	7.877
Jun-06	7.917
Jul-06	7.967
Aug-06	8.007
Sep-06	7.996
Oct-06	8.032
Nov-06	8.382
Dec-06	8.712
Jan-07	8.942
Feb-07	8.934
Mar-07	8.797
Apr-07	7.622
May-07	7.497
Jun-07	7.536
Jul-07	7.576
Aug-07	7.604
Sep-07	7.589
Oct-07	7.614
Nov-07	7.949
Dec-07	8.264
Jan-08	8.477
Feb-08	8.467
Mar-08	8.327
Apr-08	7.247
May-08	7.127
Jun-08	7.168
Jul-08	7.209
Aug-08	7.239
Sep-08	7.224
Oct-08	7.249
Nov-08	7.579
Dec-08	7.894
Jan-09	8.107
Feb-09	8.097
Mar-09	7.957
Apr-09	6.937
May-09	6.807
Jun-09	6.847
Jul-09	6.882
Aug-09	6.917
Sep-09	6.9
Oct-09	6.922
Nov-09	7.247
Dec-09	7.567
Jan-10	7.787
Feb-10	7.772
Mar-10	7.622
Apr-10	6.667
May-10	6.537
Jun-10	6.572
Jul-10	6.607
Aug-10	6.637
Sep-10	6.627
Oct-10	6.65
Nov-10	6.98
Dec-10	7.297

THE ATLANTIC COUNCIL

OF THE UNITED STATES

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The Inevitable Peaking of World Oil Production

Robert L. Hirsch

◆ *The era of plentiful, low-cost petroleum is approaching an end.*

◆ *Without massive mitigation the problem will be pervasive and long lasting.*

◆ *Oil peaking represents a liquid fuels problem, not an "energy crisis".*

◆ *Governments will have to take the initiative on a timely basis.*

◆ *In every crisis, there are always opportunities for those that act decisively.*

The era of plentiful, low-cost petroleum is approaching an end. The good news is that commercially viable mitigation options are ready for implementation. The bad news is that unless mitigation is orchestrated on a timely basis, the economic damage to the world economy will be dire and long-lasting.

Oil is the lifeblood of modern civilization. It fuels most transportation worldwide and is a feedstock for pharmaceuticals, agriculture, plastics and a myriad of other products used in everyday life. The earth has been generous in yielding copious quantities of oil to fuel world economic growth for over a century, but that period of plenty is changing.

In the following, we describe the nature of the problem, options for mitigation, and required timing. The exact date of peaking is not known; some think it will be soon, others think a decade or more. However, the date is almost irrelevant as mitigation will take much longer than a decade to become effective, because of the enormous scale of world oil consumption.

Background

Oil was formed by geological processes millions of years ago and is typically found in underground reservoirs of dramatically different sizes, at varying depths, and with widely varying characteristics. The largest oil fields[1] are called "super giants," many of which were discovered in the Middle East. Because of their size and other characteristics, super giant oil fields are generally the easiest to find, the most economic to develop, and the longest-lived. The world's last super giant oil fields were discovered in the 1960s. Since then,

[1] Oil fields are often composed of a number of individual oil reservoirs.

smaller fields of varying sizes have been found in what are called "oil prone" locations worldwide — oil is not found everywhere.

The world's last super giant oil fields were discovered in the 1960s.

The concept of the peaking of world oil production follows from the fact that the output of an individual oil field rises after discovery, reaches a peak, and then declines. Oil fields have lifetimes typically measured in decades, and peak production often occurs roughly a decade or so after discovery under normal circumstances. It is important to recognize that oil production *peaking* is not "running out." Peaking is the maximum oil production rate, which typically occurs after roughly half of the recoverable oil in an oil field has been produced. What is likely to happen on a world scale will be similar to what happens with individual oil fields, because world production is by definition the sum total of production from all of the world's oil fields.

Oil is usually found thousands of feet below the surface. Most oil fields do not have an obvious surface signature, so oil is very difficult to find. Advanced technology has greatly improved the discovery process and reduced exploration failures. Nevertheless, world oil discoveries have been steadily declining for decades, as shown below.

Oil Reserves

Oil reserves are in some ways like inventory in a business, but the analogy can be deceiving. "Reserves" is an estimate of the amount of oil in an oil field that can be extracted at an assumed cost. Thus, a higher oil price outlook often means that more oil can be produced. However, geological realities place an upper limit on price-dependent reserves growth.

Reserves estimates are revised periodically as an oil field is developed and new information provides a basis for refinement. Reserves estimation is a matter of gauging how much extractable oil resides in deep, obscure, complex rock formations, using inherently limited information. Reserves estimation is a bit like a blindfolded person trying to judge what the whole elephant looks like from touching it in just a few places. It is a far cry from counting cars in a parking lot, where all the cars are in full view.

The different estimators might calculate different reserves from the same data.

Specialists who estimate reserves use an array of technical methodologies and a great deal of judgment. Thus, different estimators might calculate different reserves from the same data. Sometimes self-interest influences reserves estimates, e.g., an oil field owner may provide a high estimate in order to attract outside investment, influence customers, or further a political agenda.

Reserves and production should not be confused. Reserves estimates are but one factor used in estimating future oil production from a given oil field. Other factors include production history, local geology, available technology, oil prices, etc. An oil field can have large estimated reserves, but if a well-managed field has past maximum production, the remaining reserves can only be produced at a diminishing rate. Sometimes decline can be slowed, but a return to peak production is impossible. This fundamental is not often appreciated by those unfamiliar with oil production.

Production Peaking

World oil demand is forecast to grow 50 percent by 2025.[2] To meet that demand, ever-larger volumes of oil will have to be produced. Since oil production from individual oil fields grows to a peak and then declines, new fields must be continually discovered and brought into production to compensate for the depletion of older fields and to meet increasing world demand. If large quantities of new oil are not discovered and brought into production somewhere in the world, then world oil production will no longer satisfy demand. Peaking means that the rate of world oil production cannot increase; it does not mean that production will suddenly stop, because there will still be large reserves remaining.

World oil demand is forecast to grow by 50 percent by 2025.

The peaking of world oil production has been a matter of speculation from the beginning of the modern oil era in the mid 1800s. Initially, little was known about petroleum geology, so predictions of peaking were no more than rank speculation. Over time, geological understanding improved dramatically and guessing gave way to more informed projections, although the knowledge base involves numerous uncertainties, even today.

As indicated in Table I (see page 9), some forecasters believe that world oil production peaking might occur very soon. Others argue that we may have more than a decade of plentiful oil, which is the position of Daniel Yergin of Cambridge Energy Research Associates, as recently expressed in an op-ed piece in the *Washington Post*.[3]

About the Author

Robert L. Hirsch is a Senior Energy Program Advisor for SAIC. Previous employment included executive positions at the U.S. Atomic Energy Commission, the U.S. Energy Research and Development Administration, Exxon, ARCO, EPRI, and Advance Power Technologies, Inc. Dr. Hirsch is past chairman of the Board on Energy and Environmental Systems at the National Academies. He has a Ph.D. in engineering and physics from the University of Illinois.

Until recently, OPEC assured the world that oil supply would continue to be plentiful, but that position is changing. Some in OPEC are now warning that oil supply will not be adequate to satisfy world demand in 10-15 years.[4] Such declarations are in line with the widely discussed questions about Saudi Arabian oil reserves raised by Matthew Simmons in his recent book.[5] Even Dr. Sadad al-Husseini, a retired senior Saudi Aramco oil exploration executive, is on record as saying that the world is heading for an oil shortage;

[2] U.S. Department of Energy, Energy Information Administration, *International Energy Outlook – 2004*, February 2004.

[3] Yergin, D. *Technology and Higher Prices Drive a Supply Buildup.* Washington Post. July 31, 2005.

[4] Moors, K.F. *How Reliable are Saudi Production and Reserve Estimates?* Dow Jones Middle East Business Strategies. July 15, 2005.

[5] Simmons, M.R. *Twilight in the Desert – The Coming Saudi Oil Shock and the World Economy.* Wiley. 2005.

in his words "a whole new Saudi Arabia [will have to be found and developed] every couple of years" to satisfy current demand forecasts.[6] So the messages from the world's "breadbasket of oil" are moving from confident assurances to warnings of approaching shortage.

At some price, world reserves of recoverable conventional oil will reach a maximum because of geological fundamentals.

Types of Oil

Oil is classified as "Conventional" and "Unconventional." Conventional oil is typically the highest quality, lightest oil, which flows from underground reservoirs with comparative ease, and it is the least expensive to produce. Unconventional oils are heavy, often tar-like and are not readily recovered because production often requires a great deal of capital investment and supplemental energy. For that reason, most current world oil production is conventional oil.[7]

The Oil Price-Reserves Nexus

In the past, higher prices led to increased estimates of conventional oil reserves worldwide. However, this price-reserves relationship has its limits, because oil is found in discrete packages (reservoirs) as opposed to the varying concentrations characteristic of many minerals. Thus, at some price, world reserves of recoverable conventional oil will reach a maximum because of geological fundamentals. Beyond that point, insignificant additional conventional oil will be recoverable at any realistic price. This is a geological fact that is often not understood by economists, many of whom are accustomed to dealing with hard minerals, whose geology is fundamentally different.

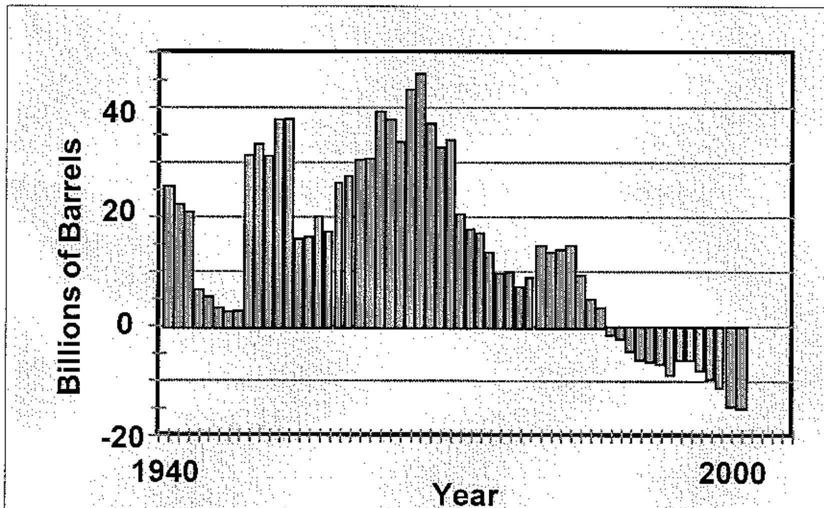

Figure 1. The net difference between annual world oil reserves additions and annual oil consumption has been declining for decades.

Oil companies and governments have conducted extensive exploration worldwide, but their results have been disappointing for decades. On this basis, there is little reason to expect that future oil discoveries will dramatically increase. The situation is illustrated in Figure 1, which shows the difference between annual world oil reserves additions and annual

[6] Haas, P. *The Breaking Point.* New York Times Magazine. August 21, 2005.
[7] U.S. Department of Energy, Energy Information Administration, *International Energy Outlook – 2004*, February 2004.

consumption.[8] The image is one of a world moving from a long period in which reserves additions were much greater than consumption, to an era in which annual additions are falling increasingly short of annual consumption. A related fact is that oil production is in decline in 33 of the world's 48 largest oil-producing countries.[9]

Impacts of Improved Technology and Higher Prices

Oil production is in decline in 33 of the world's 48 largest oil-producing countries.

Exploration for and production of petroleum has been an increasingly more technological enterprise, benefiting from more sophisticated engineering capabilities, advanced geological understanding, improved instrumentation, greatly expanded computing power, more durable materials, etc. Today's technology allows oil fields to be more readily discovered and better understood sooner than heretofore.

Some economists expect improved technologies and higher oil prices will provide ever-increasing oil production for the foreseeable future. To gain some insight into the effects of higher oil prices and improved technology on oil production, consider the history of the U.S. Lower 48 states. This region was one of the world's richest, most geologically varied, and most productive up until 1970, when production peaked and started into decline. Figure 2 shows Lower 48 historical oil production with oil prices and technology trends superimposed. In constant dollars, oil prices increased by roughly a factor of three in 1973-74 and another factor of two in 1979-80. In addition to these huge oil price increases, the 1980s and 1990s were a golden age of oil field technology development, including practical 3-D seismic, economic horizontal drilling, dramatically improved geological understanding, etc. Nevertheless, as Figure 2 shows, Lower 48 oil production still trended downward, showing no pronounced response to either price or technology. In light of this experience, there is no reason to expect that the worldwide situation will be different: Higher prices and improved technology are unlikely to yield dramatically higher conventional oil production.

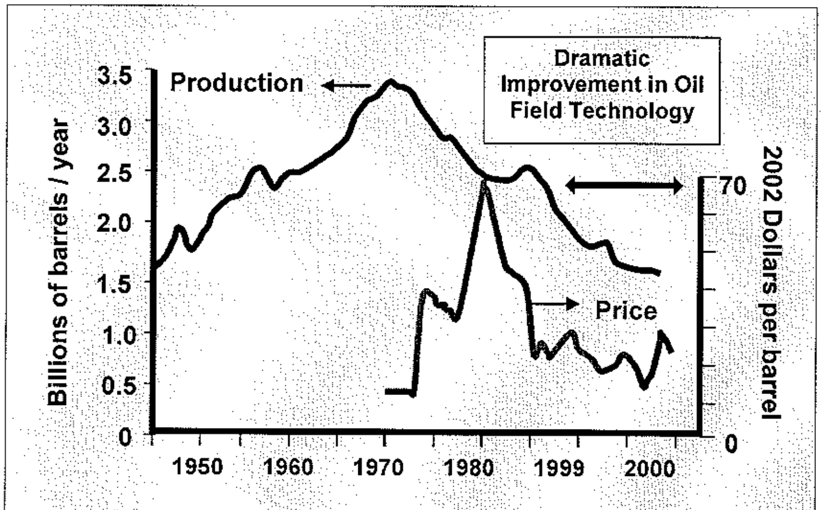

Figure 2. The decline of U.S. Lower 48 oil production was not reversed by large changes in oil prices or the dramatic improvement in oil field technologies.

[8] Aleklett, K. & Campbell, C.J. *The Peak and Decline of World Oil and Gas Production.* Uppsala University, Sweden. ASPO web site. 2003.

[9] O'Reilly, D.J., Chairman and CEO, Chevron Corporation. Washington Post. July 25, 2005.

Peaking of World Oil Production

Various individuals and groups have used available information and geological tools to develop forecasts for when world oil production might peak. A sampling is shown in Table 1, where it is clear that many believe that peaking is likely within a decade.

Mitigation

A recent analysis for the U.S. Department of Energy addressed the question of what might be done to mitigate the peaking of world oil production.[10] Various technologies that are commercial or near commercial were considered:

1. Fuel efficient transportation,
2. Heavy oil/oil sands,
3. Coal liquefaction,
4. Enhanced oil recovery,
5. Gas-to-liquids.

It became abundantly clear early in this study that effective mitigation will be dependent on the implementation of mega-projects and mega-changes at the maximum possible rate. This finding dictated the focus on currently commercial technologies that are ready for implementation. New technology options requiring further research and development will undoubtedly prove very important in the longer-term future, but they are not ready now, so their inclusion would be strictly speculative.

A scenario analysis was performed, based on crash program implementation worldwide – the fastest humanly possible. Three starting dates were considered:

1. When peaking occurs;
2. Ten years before peaking occurs; and
3. Twenty years before peaking.

Effective mitigation will be dependent on the implementation of mega-projects and mega-changes at the maximum possible rate.

The timing of oil peaking was left open because of the considerable differences of opinion among experts. Consideration of a number of implementation scenarios provided some fundamental insights, as follows:

- Waiting until world oil production peaks before taking crash program action leaves the world with a significant liquid fuel deficit for more than two decades.
- Initiating a mitigation crash program 10 years before world oil peaking helps considerably but still leaves a liquid fuels shortfall roughly a decade after the time that oil would have peaked.
- Initiating a mitigation crash program 20 years before peaking offers the possibility of avoiding a world liquid fuels shortfall for the forecast period.

[10] Hirsch, R.L., Bezdek, R. and Wendling, R. *Peaking of World Oil Production: Impacts, Mitigation, and Risk Management.* DOE NETL. February 2005.

The reason why such long lead times are required is that the worldwide scale of oil consumption is enormous – a fact often lost in a world where oil abundance has been taken for granted for so long. If mitigation is too little, too late, world supply/demand balance will have to be achieved through massive demand destruction (shortages), which would translate to extreme economic hardship. On the other hand, with timely mitigation, economic damage can be minimized.

Warning Signs

In an effort to gain some insight into the possible character of world oil production peaking, a number of regions and countries that have already past oil peaking were recently analyzed.[11] Areas that had significant peak oil production and that were not encumbered by major political upheaval or cartel action were Texas, North America, the United Kingdom, and Norway. Three other countries that are also past peak production, but whose maximum production was smaller, were Argentina, Colombia, and Egypt.

Examination of these actual histories showed that in all cases it was not obvious that production was about to peak a year ahead of the event, i.e., production trends prior to peaking did not provide long-range warning. In most cases the peaks were sharp, not gently varying or flat topped, as some forecasters hope. Finally, in some cases post-peak production declines were quite rapid, as in the U.K. for example (Figure 3)

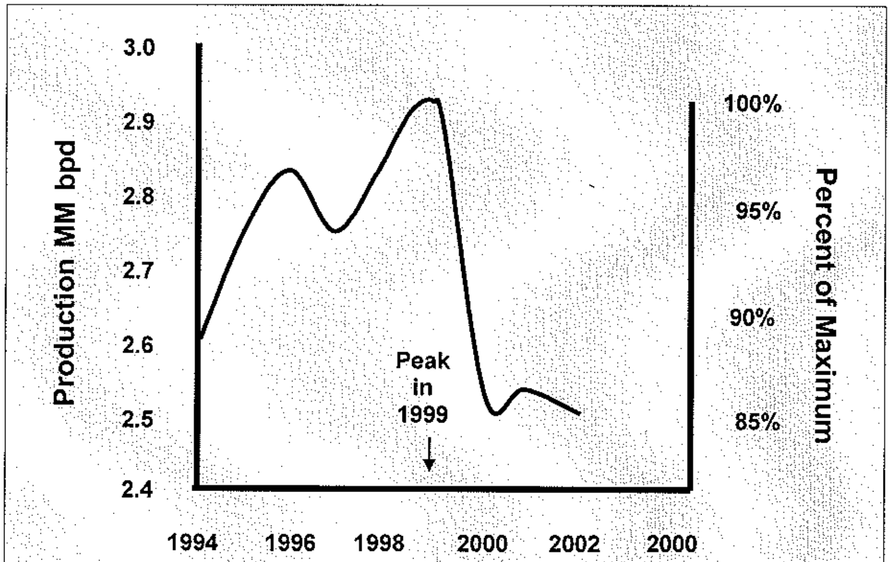

Figure 3. Oil production in the United Kingdom peaked in 1999 on very short notice. After the peak, the decline in production was very rapid.

It is by no means obvious how world oil peaking will occur, but if it follows the patterns displayed by these regions and countries, the world will have less than a year's warning.

It's Not Your Mother's Energy Crisis

Oil peaking represents a liquid fuels problem, not an "energy crisis" in the sense that term has often been used. Motor vehicles, aircraft, trains,

[11] Hirsch, R.L. *The Shape of World Oil Peaking: Learning From Experience.* To be published.

and ships simply have no ready alternative to liquid fuels, certainly not for the existing capital stock, which have very long lifetimes. Non-hydrocarbon-based energy sources, such as renewables and nuclear power, produce electricity, not liquid fuels, so their widespread use in transportation is at best many decades in the future. Accordingly, mitigation of declining world conventional oil production must be narrowly focused in the near-term.

Risk Management

It is possible that peaking may not occur for a decade or more, but it is also possible that peaking may be occurring right now. We will not know for certain until after the fact. The world is thus faced with a daunting risk management problem. On the one hand, if peaking is decades away, massive mitigation initiated soon would be premature. On the other hand, if peaking is imminent, failure to quickly initiate mitigation will impose large near-term economic and social costs on the world.

The two risks are asymmetric:

- Mitigation initiated prematurely would result in a relatively modest misallocation of resources.
- Failure to initiate timely mitigation with an appropriate lead-time is certain to result in very severe economic consequences.

The world has never confronted a problem like this. Risk minimization requires the implementation of mitigation measures well prior to peaking. Since it is uncertain when peaking will occur, the challenge for decision-makers is indeed vexing. Mustering support for an invisible disaster is much more difficult than for one that is obvious to all.

The world is faced with a daunting risk management problem.

Concluding Remarks

Over the past century, world economic development has been fundamentally shaped by the availability of abundant, low-cost oil. Previous energy transitions (wood to coal, coal to oil, etc.) were gradual and evolutionary; oil peaking will be abrupt and revolutionary.

The world has never faced a problem like this. Without massive mitigation at least a decade before the fact, the problem will be pervasive and long lasting.

Oil peaking represents a liquid fuels problem, not an "energy crisis" in the sense that term has been used. Accordingly, mitigation of declining world oil production must be narrowly focused, at least in the near-term.

A number of technologies are currently available for immediate implementation once there is the requisite determination to act. Governments worldwide will have to take the initiative on a timely basis, and it may already be too late to avoid considerable discomfort or worse. Countries that dawdle will suffer from lost opportunities, because in every crisis, there are always opportunities for those that act decisively.

Table 1: Projections of the Peaking of World Oil Production

Projected Date	Source of Projection	Background & Reference
2006-2007	Bakhitari, A.M.S.	Oil Executive (Iran)[1]
2007-2009	Simmons, M.R.	Investment banker (U.S.)[2]
After 2007	Skrebowski, C.	Petroleum journal editor (U.K.)[3]
Before 2009	Deffeyes, K.S.	Oil company geologist (ret., U.S.)[4]
Before 2010	Goodstein, D.	Vice Provost, Cal Tech (U.S.)[5]
Around 2010	Campbell, C.J.	Oil geologist (ret., Ireland)[6]
After 2010	World Energy Council	World Non-Government Org.[7]
2012	Pang Xiongqi	Petroleum Executive (China)[8]
2010-2020	Laherrere, J.	Oil geologist (ret., France)[9]
2016	EIA nominal case	DOE analysis/ information (U.S.)[10]
After 2020	CERA	Energy consultants (U.S.)[11]
2025 or later	Shell	Major oil company (U.K.)[12]

[1] Bakhtiari, A.M.S. *World Oil Production Capacity Model Suggests Output Peak by 2006-07. Oil and Gas Journal.* April 26, 2004.
[2] Simmons, M.R. ASPO Workshop. May 26, 2003.
[3] Skrebowski, C. *Oil Field Mega Projects - 2004.* Petroleum Review. January 2004.
[4] Deffeyes, K.S. *Hubbert's Peak-The Impending World Oil Shortage.* Princeton University Press. 2003.
[5] Goodstein, D. *Out of Gas – The End of the Age of Oil.* W.W. Norton. 2004
[6] Campbell, C.J. *Industry Urged to Watch for Regular Oil Production Peaks, Depletion Signals. Oil and Gas Journal.* July 14, 2003.
[7] *Drivers of the Energy Scene.* World Energy Council. 2003.
[8] Pang Xiongqi. *The Challenges Brought by Shortages of Oil and Gas in China and Their Countermeasures.* ASPO Lisbon Conference. May19-20, 2005.
[9] Laherrere, J. Seminar Center of Energy Conversion. Zurich. May 7, 2003
[10] DOE EIA. *Long Term World Oil Supply.* April 18, 2000. See Appendix I for discussion.
[11] Jackson, P. et al. *Triple Witching Hour for Oil Arrives Early in 2004 – But, As Yet, No Real Witches. CERA Alert.* April 7, 2004.
[12] Davis, G. *Meeting Future Energy Needs.* The Bridge. National Academies Press. Summer 2003.

Acknowledgements

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Oil Depletion? It's All In The Assumptions

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2 August 2005

> **In Brief:** Ron Cooke, author of 'Oil, Jihad and Destiny' examines Daniel Yergin's Cambridge Energy Research Associates(CERA) report 'Worldwide Liquids Capacity Outlook To 2010— Tight Supply Or Excess Of Riches' He shows that it is based on numerous assumptions that can not neccessarily be counted on in reality and contrasts CERA's view with a number of more skeptical opinions from within the industry.

Good News

In good news for the SUV set, Daniel Yergin's Cambridge Energy Research Associates (CERA), is predicting we will soon be awash in light, sweet crude - ideal for making gasoline.

CERA's Worldwide Liquids Capacity Outlook To 2010— Tight Supply Or Excess Of Riches predicts we humans will have 6 to 7.5 million barrels per day of excess capacity and we can expect an extended period of lower prices – perhaps by 2007. Petroleum production will be expanding faster than demand over the next 5 years. The report has tabulated 20 to 30 new projects with a capacity of over 75,000 barrels per day that will become available in each and every year until 2010. By then, worldwide production could increase by up to 16 million Bbl/day. However, most of the increased production will come from reworking existing fields, rather than new oil discoveries, and after 2010 the majority of new production will come from OPEC.

CERA doesn't believe in peak oil, at least not before 2010, and probably not before 2020. The report indicates that the "inflexion" point will come between 2030 and 2040. Moreover, rather than a "peak," it will be an "undulating plateau" that will continue for several decades. OPEC, the company claims, will be able to add 8.8 Mbl/day by 2010 and can continue its expansion – at a somewhat slower rate – beyond 2010. Non-OPEC production will experience a robust increase through 2010, and then slow significantly thereafter. Unconventional oil production will increase throughout this period, supplying almost 35 percent of the world's oil by 2020.

Then Yergin adds a sobering caveat: "The main risks to our Supply Expansion scenario are above ground, not below ground – changes in the political and operating climate that could delay expansion." In CERA's downside "Delay and Disruption" scenario, capacity increases by only 11.5 million barrels between 2004 and 2010.

Whoops.

What is the implication? Will delayed projects and disruptions in the supply chain lead to temporary shortages before "Peak Oil" hits us? Perhaps we should review CERA's implied assumptions. They are, after all, the basis of CERA's optimistic conclusions.

Assumptions

Underlying every data analysis and series of conclusions is a collection of assumptions. In order to avoid oil shortages, temporary or longer term, for example, we have to make multiple assumptions about our ability to find, produce, transport, refine and distribute oil (the supply chain). At some point in our analysis, these assumptions have to be tested for credibility.

Will they hold up under careful examination?

Assumption # 1. Peace in Iraq.

A key element for any increase in Middle East oil production has to be Iraq. Estimates of found oil range from 46 to 112 Bbl, with another 100 Bbl a strong "maybe it's there". If there is no peace in Iraq, or if Iraq succumbs to the policies of an Islamic Theocracy, then Iraq's contributions to OPEC's annual production volumes will never reach the levels envisioned by the International Energy Agency (IEA). If Iraq's government is stable, and favors a high production policy, then world oil supplies will be a little closer to the IEA's projections through 2020.

The future of Iraq rests on the outcome of an escalating cultural conflict between Islamist and Western values. Until that gets resolved, we can only guess at the future of Iraqi oil production.

Assumption # 2. Political and labor stability.

Any optimistic analysis of oil production must assume there will be relative political and labor stability in the Middle East, North West Africa, South America, and Caspian regions. As recent events have shown, however, these areas are prone to conflict that disrupts the flow of oil. Up until 2004, temporary disruptions in one region could usually be replaced by production from other resources. Going forward, there may not be sufficient spare capacity to cover lost production from one or more regions. As a result, sporadic shortages are a possible reality.

Assumption # 3. Islamist terrorist activity will not disrupt the supply chain.

Islamist terrorist activity will continue to disrupt the supply chain from time to time. The land locked Caspian, for example, could be the source of 60 Bbl of oil. Maybe more. And these wells are coming on-line. But most of the oil in this region must pass through a very long pipeline in order to reach the consumer. History suggests political volatility in this region will eventually disrupt supply chain operations. Perhaps for multiple years.

Islamist terrorist activity, whether sporadic or sustained, will continue to be a potential threat to the flow of oil, not only in the nations of the Caspian, the Middle East, and North West Africa, but also within the borders of consuming nations.

Assumption # 4. The proven reserves claimed by OPEC actually exist.

It is unlikely the proven reserves claimed by OPEC actually exist. Many believe they are a fabrication of the quota justifications that occurred in the 1980s. Furthermore, the claim that "Proven" reserves are increasing needs to be examined because in a sense we are merely talking about definitions. Words. As the price of oil increases, it becomes economically feasible to spend more money on production. Make sense? So the reserves that could not be classified as "Proven" at $26.00 per barrel become damn attractive if the price for a barrel goes to $55.00. There isn't any more oil. It's just that "Probable" oil reserves become "Proven" oil reserves as the price of oil increases because we can afford to spend more money on recovery. All we did was reclassify the definition of the oil we already have in the ground. No one found any more oil. Not a drop.

Assumption # 5. There will not be a substantial increase in reserve depletion rates.

Only 4 "super-giant" oilfields have been found outside the Middle East since 1960 (in Russia, China, Alaska and Mexico) and all of these - except China - are now in decline. Oil production is in decline in 33 of the 48 largest oil producing nations. Using improved technology often increases the rate of depletion. New finds tend to be smaller and deplete faster. Worldwide, estimated rates of depletion run as high as 8 percent per year.

Assumption # 6. All proven and potential reserves will be produced on schedule.

This assumption only works if hundreds of exploration and drilling operations in multiple countries and oceans under a wide variety of operating conditions and technical challenges occur on a schedule that coincides with the IEA's demand projections. Everything has to work. No significant political or labor conflicts. No ideological confrontation. No financing or management Snafus. Cooperative weather. And a reasonably predictable growth in market demand so consumption can equal production (with a little to spare).

Assumption # 7. Middle Eastern production capacity will continually increase, reaching ~ 29 Mbl/d by 2010 and at least 43 Mbl/d by 2020.

Middle Eastern production capacity will increase. The goal of 29 Mbl/day by 2010, however, is ambitious, and few believe OAPEC will be able to deliver 43 to 50 Mbl/day by 2020. Exploration and production will be challenged by Islamist opposition in Iran, Iraq and Saudi Arabia (and perhaps elsewhere). There is a long list of reserve and technical restraints in this region. We must also understand that the creation of a large surplus capacity is NOT in OAPEC's selfish best interest. Faced with enormous population growth and big welfare bills, every Middle Eastern government knows that when the oil is gone, their regime is in trouble. Leaders may determine they can actually make more money, and enjoy greater personal longevity, - by pumping less.

Assumption # 8. The EROEI of all oil production exceeds 1.

EROEI. Energy Returned On Energy Invested means that the energy derived from exploration, production, refining, and transportation exceeds the energy consumed for these activities. We tend to forget. If the EROEI of any energy resource is 1 or less, then doing that activity no longer provides a net addition to our stockpile of energy.

The average EROEI of world oil production has been declining. I read somewhere that before 1950 the EROEI for oil was more than 100:1. By the 1970s it had dropped to 30:1, and by 2005 the average EROEI on new production had fallen to 10:1. As we go for oil in increasingly difficult environments (deep under the ocean, open pit mining, etc.) the EROEI will decline further. We have to face the facts. Just because there is oil in the ground does not mean it is practical to extract. Every well has its cost in money AND energy. At some point the EROEI for every well will fall to less than 1, making oil from that well an impractical resource for energy.

Assumption # 9. Unconventional oil production will increase throughout this period, supplying almost 35 percent of the world's oil by 2020.

We have inherited up to 7 Tbls of oil trapped in sand or shale formations. But that is a misleading number. Only 5 Tbl are worth mining and of that number, perhaps 25 percent will be feasible to produce because production cost and EROEI factors make extensive mining impractical. Given the production problems associated with squeezing oil from rock and sand, the rate of production will be painfully slow. A goal of 15 to 18 Mbl per day by 2020 from recoverable reserves of 620 to 910 Bbl appears reasonable.

We expect to find oil beneath polar ice and permafrost in the Artic. Although total recoverable oil is something of a mystery at this point, figure 55 to 100 Bbl (maybe more). Unfortunately, exploration, production and transportation in this frigid environment are no fun. And costly. So don't expect polar oil to yield enough production to avoid oil shortages.

We are learning how to drill in the deep waters (over 2,500 meters) of the ocean. There is oil in the Gulf of Mexico, along the coastal shelves of South America and Africa, and a number of other locations around the world. Recovery takes time, is a technical and operations challenge, and is very costly. Add another 80 to 120 Bbl of oil to the reserves we will ultimately recover.

In addition, one can expect we humans will pump out a limited amount of heavy oil and oil from coal bed methane deposits.

If we add up all of these resources, we probably have up to 1.1 Tbl of unconventional oil to play with over the next 20 years. But our estimate of annual production is much lower. Technical, weather, geography, political, environmental, cost and EROEI factors will limit total production to around 100 Bbl from 2005 to 2020. This estimate – by the way - mirrors the Energy Outlook projections made by ExxonMobile in its "World Liquids Production Outlook" presentation.

To these numbers we need to add, as CERA does, Natural Gas Liquids (NGL) and condensates as unconventional oil. If we add all of these forms of unconventional oil together, CERA's projections appear reasonable.

Assumption # 10. There is sufficient infrastructure to support a vigorous increase in production.

Oil is a cyclical business. Prices bounce up and down because there is almost always a mismatch between supply and demand. For a number of reasons, exploration and production investments have not kept up with projected increases in demand. That investment deficit has left us with insufficient spare production capacity to sustain the world's projected economic growth. Even if we have ample reserves in the ground, there is no guarantee enough oil wells will be developed in time to avoid sharply higher prices and possible shortages. We don't have enough oil rigs, tankers, petroleum engineers, or refinery capacity. The problem is systemic and will take several years to resolve.

Assumption # 11. Non-Muslim engineers, technicians and laborers will be permitted to work in the fields of the Middle East, North West Africa, and countries adjacent to the Caspian basin.

Non-Muslim engineers, technicians and laborers will be permitted to work in the fields of the Middle East, North West Africa, and countries adjacent to the Caspian basin. However, Islamist activity and local sociopolitical conflict could jeopardize personnel security. Iran's new government, for example, has made it clear that non-Muslim foreigners are not welcome to bid, or work, in Iran's oil patch.

Assumption # 12. There is sufficient capital to fund the proposed supply chain activities.

There is sufficient capital to fund all of the proposed supply chain activities if one assumes the credit markets will not be overly stressed by other economic events, such as a collapse of the market for Mortgage Backed Securities or a massive default on the loans outstanding to Hedge Funds.

Assumption # 13.There will be a dramatic decrease in the growth rate of oil consumption.

Emerging nations, like China and India, will increase their per-capita and total consumption of oil. Although I fully expect a decrease in the growth rate of oil consumption will occur, it will - as I point out in "Oil, Jihad and Destiny" – be due to recessive factors. Production will equal consumption only if there is a destruction of natural demand or if shortages force reduced consumption. In either case, the rate of growth decreases.

Assumption # 14. As a result of over production, we will be awash in oil.

It is more likely that Saudi Arabia will continue to act as a swing producer, restricting its production in order to encourage higher prices. Indeed, Saudi Aramco engineers may welcome the opportunity to take key wells off-line for service if the world appears to be "awash" in oil.

Assumption # 15. The price of oil will decline.

It is highly likely that the price of oil will fall below $40.00 per barrel. The history of the oil industry is characterized by volatile changes in price because of the chronic imbalance between supply and demand. But a temporary decline in price is no basis for making either public policy or personal choice decisions. For every short term decline, expect a subsequent increase in the price. The long term trend for all petroleum prices is UP.

Assumption # 16. Resource nationalism will not disrupt world oil markets.

If there is so much oil available for production, why are we drilling new wells in deep water? They are very expensive, challenge our best technology, pose an environmental hazard, and are at the mercy of the sea. Why don't we just drill on land?

Because the North Sea fields are declining, West Africa is in turmoil, Venezuela is politically unstable, Iraq is a crap shoot, Saudi Arabia is vulnerable to revolution, and Putin plans to use Russia's petroleum as a political weapon. China is buying up every drop it can find. The Italians have pointed out that the geographical flows of crude oil favor refineries on the Mediterranean coast over refineries located in North America.

Hmmmm. Are we witnessing an increase in resource nationalism?

The industrialized nations have no choice. Oil shortages will create a growing cadre of unemployed citizens and declining GDP. Political survival means drilling in every plausible location on this planet and competing with other nations for the oil that is left.

The race is on.

Assumption # 17. Technology will save us.

Optimists claim that continuing improvements in computer, exploration, and drilling technology will sharply increase oil production. In truth, the oil industry has been continually improving upstream exploration and production technology since the birth of the oil age. Engineers are currently hard at work on improvements for drilling fluids, drill bits, directional drilling, multilateral drilling, sensors, GPS, drill casing materials, CO2 injection, reservoir modeling software, and a thousand other opportunities to increase recovery operations. The point is, there is no magic solution that will suddenly increase our reserves. Almost every technical solution has already been explored. Yes. New technologies will increase production. But the net impact is more likely to be incremental – not revolutionary.

For example, much has been made about the use of CO2 injection to increase recoverable reserves. Granted. It is possible to recover 60 percent (or more) of the oil that in the ground as we humans struggle to liberate every drop of oil from existing reservoirs. But many of our older oil formations have already been flushed with fluids and chemicals in an effort to increase production. Consequently, the use of newer technology will not always yield dramatic improvements in mature field recovery. New finds, on the other hand, provide an opportunity to secure higher increases than older formations. Recovery rates will also be higher and faster for light oils than for heavier crude. And finally, it may - or may not - be economical to use newer technology, such as CO2 injection, on some wells. What does this all mean? Over a period of years, average world recovery rates are more likely to be in the 45 to 50 percent range.

And there is a downside to the application of reserve enhancement technology. If we increase the rate at which we drain our available reserves, - depletion happens sooner.

Assumption # 18. Higher prices will encourage the production of more oil.

The classic economist assumes higher prices will stimulate greater production. And it usually works. But our hydrocarbon resources are finite. New production involves a complex series of challenges that can take several years to overcome. In order to continue along the growth curve of projected demand through 2020, we humans will have to consume most of our "Proven" reserves, convert most of our "Probable" reserves into "Proven" reserves, and maximize a phenomenon peculiar to the petroleum industry called "Reserve Growth". Oil prices will have to increase in order to justify the economics of this sequence. Total oil production, however, will continue to be limited by the factors discussed above in Assumptions 1 – 17.

Reality Check

CERA's optimistic views are in the minority.

John S. Herold, Inc. Wall Street firm John S. Herold Inc. of Norwalk, CT (http://www.herold.com/) has estimated peak production for about two dozen oil companies. Without substantial new investment and additional discoveries, the company believes that French oil company, Total S.A., will reach peak production in 2007. Exxon Mobil, ConocoPhillips, BP, Royal Dutch/Shell Group, and the Italian producer, Eni S.p.A. will hit peak production in 2008. In 2009, Herold expects ChevronTexaco Corp. to peak. In Herold's view, each of the world's seven largest publicly traded oil companies will begin seeing production declines within the next 48 months or so.

PFC Energy From the July 1, 2005 edition of the Washington Post comes this commentary by Robin West, in an article entitled "Crude Courage"

"J. Robinson West, chairman of the consulting group PFC Energy, has floated with administration officials his idea of a sustained national dialogue on energy that includes all stakeholders. And his group has gathered what may be the best statistics available on the seriousness of the supply-demand crunch.

West argues that the oil market squeeze will only get worse -- and more vulnerable to political disruptions. By his estimate, about 77 percent of proven oil reserves are controlled by nationalized oil companies rather than by the international majors such as Exxon Mobil. Meanwhile, non-OPEC sources of supply are slowly declining. …. Even if more crude were suddenly discovered, there's a worldwide refining squeeze, with almost no spare capacity left. The day of reckoning is less than 15 years away, by West's calculation. Assuming fairly slow growth in demand of about 1.8 percent annually, he reckons that by 2020 demand will total over 100 million barrels per day, and OPEC will be unable to fill the supply gap. Unless the United States and other consuming countries have taken steps to reduce consumption, the supply-demand imbalance will throw the world into economic chaos ….. "

ChevronTexaco Dave O'Reilly, the chairman of ChevronTexaco: "The time when we could count on cheap oil and even cheaper natural gas is clearly ending." Chevron has started a petroleum resource discussion on the WEB at http://www.willyoujoinus.com/. Vice President of Policy, Government and Public Affairs, Patricia Yarrington believes the site is an important first step in a new dialogue. "We developed a campaign that is rooted in the real issues facing our industry. They are issues that affect everyone who has a stake in energy – consumers, businesses, policymakers, environmentalists, educators and political leaders. We think it's a very compelling campaign about a very compelling subject."

ExxonMobile ExxonMobile projects non-OPEC Crude and Condensate production will plateau before 2015 in its Energy Outlook presentation. ExxonMobil proposes that increased demand be met in two ways. The first is greater fuel efficiency. (How often do you hear oil companies pleading with us to buy cars that use less gas?). The second way is for OPEC to vastly increase production.

We should pay attention to ExxonMobile's judgment. "This assessment (of increased OPEC production) is somewhat ominous" writes Dr. Colin Campbell, a founder of ASPO, "… such production increases are only possible from Iraq, Saudi Arabia, Kuwait, and the United Arab Emirates. For these countries, and indeed for most OPEC members, petroleum and petroleum products are their only significant export. As such, they have a vested interest in obtaining the best possible price for their non-renewable resources. OPEC nations would be quite unlikely to increase production as rapidly as needed unless compelled to do so." And in the ASPO Newsletter 55 (July 2005), Dr. Campbell writes "It is significant that the first quarter production of most of the major oil companies is falling : ExxonMobil -3%; Chevron -6% ; Shell -8% ; Repsol YPF -7%., while Phillips-Conoco maintained its level with BP at least reporting a 2% increase (see Petroleum Review, June 2005). All the more reason that the public should heed the silent alarm sounded by the ExxonMobil report, which is more credible than other predictions for several reasons. First and foremost is that the source is ExxonMobil. No oil company, much less one with so much managerial, scientific, and engineering talent, has ever discussed peak oil production before. Given the profound implications of this forecast, it must have been published only after a thorough review."

Shell The Royal Dutch/Shell Group of Companies, in their presentation "Visions of the Future: Shell launches new Global Scenarios looking forward to 2025" lays out the risks: " The energy scene will be reshaped by the combination of three discontinuities: a relinking of energy consumption and economic growth as a result of the faster development of emerging countries, the emergence of carbon as a commodity in its own right, and the search for energy security. The latter will remain a key consideration during the scenario time span, potentially leading to far more politicized energy relations and creating new sources of tensions among countries as well as new opportunities for entrepreneurship and cooperation. Ambiguity will persist as to what the term "energy security" covers: physical supplies can be threatened by rising international insecurity as well as by depletion of supply sources. Insecurity can also result from the lack of investment in enhanced recovery of existing sources, in new energy sources and/in infrastructures."

Aramco Although Aramco, Saudi Arabia's national oil company (and the largest oil company in the world), has launched a massive expansion program, it could be 5 to 7 years before we see any meaningful increase in production from this additional investment. Worse, Saudi officials have apparently told the Bush Administration that OPEC will be unable to meet projected oil demand in 10 to 15 years. Saudi Arabia would have to produce up to one half of the increased demand, with most of the remainder coming from Kuwait, the United Arab Emirates, and Iraq. In order for the CERA scenario to work, the cartel would have to boost its production to 50 Mbl/d. Few believe that will happen. Saudi Arabia, for example, has apparently calculated that its contribution will fall short by up to 5 Mbl/d by 2024.

BP Only BP appears to agree with CERA. There "is no shortage of oil and gas resources for the long term" (From "Making the right choices, The energy year in perspective"). The world has enough proved reserves of oil to last 40 years "at current consumption levels". Higher prices, BP claims, have been caused by a supply-demand imbalance that should be resolved with the addition of new production over the next few years. Incidentally, BP is the only major independent oil company that had more reserves at the end of 2004 than it had at the beginning of that year.

Conclusion

Delayed projects and disruptions in the oil supply chain, coupled with current rates of depletion, could lead to temporary shortages long before "Peak Oil".

Why? Because the issue is NOT how much oil do we have left in the ground. The issue is – How much oil can we produce? Sure. Calculating available reserves (proven, probable, and possible) is important because these projections give us a rough idea when peak oil production will occur. But when we talk about oil as a business, we have to include the challenges of exploration, production and transportation. It will be tough, for example, to find and pump this stuff from black holes in remote Siberia or the cold blue ice of the Artic. Emerging technologies may permit us to drill 10,000 meters below the surface of the ocean, but it's still an incredible operations headache. Producing oil from shale and sand is possible, but finding enough water and natural gas to sustain production will be difficult. And then there's another problem. Most of the world's remaining reserves and transport routes are located within the boundaries of nations that are politically unstable, have unpredictable regimes, may ignore their contractual obligations, or have a large faction of politically active extremists.

Given the seemingly infinite number of imponderable variables and assumptions, a credible forecast based on available information (facts) is impossible. That's why I developed a series of scenarios for my book - Oil, Jihad and Destiny. Each scenario provides a way to organize a set of related facts and assumptions. Because they begin as a hypothesis, scenarios can be tested against known data points. We can also estimate each scenario's probability. Although the resulting "Best Case" scenario in my model projects adequate oil production through 2020, I gave it a probability of only 40 percent. The "Production Crisis" in my book describes a more likely scenario. Oil shortages will drive intermittent periods of recessive economic activity. Recession drives down demand. Oil surpluses appear and prices decline. A sluggish economic recovery occurs until oil production again falls behind demand. Consumption then decreases or is stagnant, and the cycle is repeated.

In the final analysis, however, the pivotal point for all of these assumptions and scenarios rests on the motivations, political realities, and production capabilities of the Middle East. If they are willing to act in the selfish-best-interest of the industrialized nations, then CERA's "Best Case" scenario is possible.

If not, we are in for a long period of cultural and economic agony.

Ronald R. Cooke The Cultural Economist Author: Oil, Jihad and Destiny

Official Market Price Projection

0905 Official 09-30-05

PACIFICORP

OVERVIEW:

There are several changes to this update. The most significant updates include:

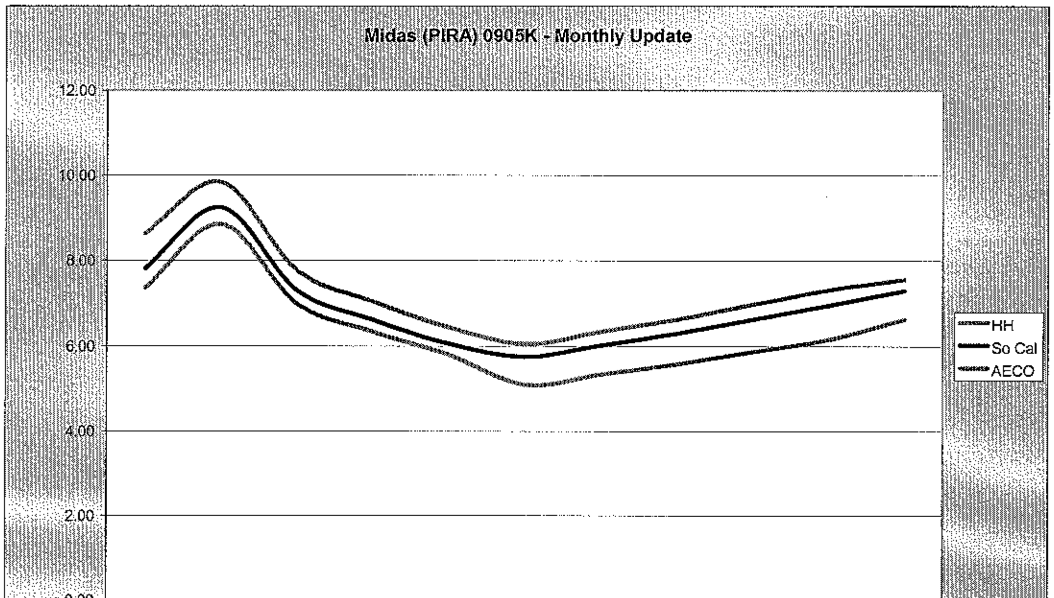
- September inflation
- Renewable portfolio standards
- Market calibration

Summarized below are major assumptions and inputs to this projection. Detailed back-up documentation is maintained in the 0905 binder.

GAS PRICES AS INPUT IN MIDAS: *UPDATED FOR 0905*

Natural gas price assumptions are based on PIRA's August 30, 2005 short-term forecast and the July 14, 2005 long-term gas forecast. The August short-term forecast did not include updates for Sumas and PG&E. For these two hubs, Bloomberg historical bases were used: the historical spread between Sumas and Stanfield was used to derive Sumas and the spread between Malin and PG&E was used to derive PG&E. PIRA gas price projections are used in Midas through 2015. Gas prices from 2016 and beyond are escalated using PacifiCorp's inflation curve, which was updated on September 9th, 2005.

Including the effect of PacifiCorp inflation, Henry Hub increased to $9.84 in 2006 from $7.84 in 0605I. Similarly, SoCal gas increased to $9.24 in 2006 from $7.42 in 0605I. The increases in forecasted prices do not directly impact the forward price curve because they are within the market-derived curve horizon. The average change in forecasted prices from the 0605 curve for major western hubs was 1.6% higher in 2015. The following chart shows the PIRA annual gas prices used in Midas for AECO, Henry Hub and SoCal.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
HH	8.63	9.84	7.77	7.04	6.44	6.05	6.33	6.62	6.97	7.31	7.56
So Cal	7.81	9.24	7.30	6.61	6.05	5.75	6.02	6.29	6.62	6.95	7.30
AECO	7.35	8.86	6.99	6.33	5.79	5.09	5.33	5.58	5.87	6.16	6.63

CERTIFICATE OF SERVICE

I hereby certify that on the 9th day of December 2005, I served the foregoing Testimony of Carel DeWinkel, Jeff Keto and Phil Carver upon the persons named on the attached UM 1129 service list by electronic mail and by mailing a full, true and correct copy thereof addressed to the persons at the addresses on the UM 1129 service list.

DATED: December 9, 2005

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Janet L. Prewitt, #85307
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