Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • Facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

July 11, 2007

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem, OR 97308-2148

Re: UE 188 – 2008 Rate Case (Biglow Canyon Wind Farm)

Attention Filing Center:

Enclosed for filing in UE 188 on behalf of Portland General Electric Company are an original and five copies of:

- **Rebuttal Testimony of Randy Dahlgren and Jay Tinker (PGE/500) Policy**

Also enclosed are three copies of:

- **Workpapers.** (Not to be posted on the PUC website).

These documents are being filed electronically. Hard copies will be sent via postal mail.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:jbf
Enclosures
cc: Service List-UE 188

RECEIVED

JUL 12 2007

Public Utility Commission of Oregon
Administrative Hearing Division

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 188

General Rate Case Filing
Biglow Canyon
For Prices Effective January 1, 2008

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits

July 11, 2007

UE 188 / PGE / 500
DAHLGREN - TINKER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Randy Dahlgren
Jay Tinker

July 11, 2007

I. Introduction

Q. What are your names and positions with Portland General Electric?

A. My name is Randy Dahlgren. I am Director, Regulatory Policy and Affairs. My qualifications were previously provided in PGE Exhibit 100.

My name is Jay Tinker. I am a project manager for PGE. My qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to the testimony of the OPUC Staff, Citizens Utility Board (CUB), and Industrial Customers of Northwest Utilities (ICNU).

Q. Have the parties filed a stipulation in this proceeding?

A. Yes. On June 20, the parties filed a stipulation covering the cost of service issues associated with Biglow Canyon 1 for 2008.

Q. What issue remains for the Commission to decide?

A. The remaining issue is a significant regulatory policy issue: whether it is appropriate to establish a process to update the fixed cost revenue requirement of Biglow Canyon 1 outside of a general rate case, or in the alternative, establish a mechanism (e.g., levelization) that anticipates and estimates post-2008 changes in Biglow Canyon 1 revenue requirement and factors the anticipated effect into Schedule 120 beginning January 1, 2008.

Q. Does the OPUC Staff support an annual update procedure for Biglow's fixed revenue requirement?

A. No, at least not at this time. (Staff/100, Owings/4). Staff recognizes this is an important policy issue that clearly has implications not only for Biglow Canyon 1, but also for future renewable resource acquisitions by PGE or PacifiCorp as a result of SB 838. (Staff/100, Owings/6).

Q. Do you agree with Staff that the Commission should open an investigation into the appropriate rate making treatment of renewable resources?

A. Yes, although we note that the Commission is opening a rulemaking proceeding on the automatic adjustment clause under SB 838, which may also be an appropriate forum to address this question. In any case, it would seem inappropriate to make a policy determination with such significant consequences beyond Biglow Canyon 1, or even PGE, within the context of this docket.

Q. How does CUB describe recent changes in the regulatory environment for PGE?

A. CUB describes the regulatory environment as being unbalanced, with the regulatory lag borne by the utility significantly diminished while the lag borne by customers remains unchanged. (CUB/100, Jenks/2). CUB goes so far as to suggest that PGE "systematically over-charge[s] for the rate base value of generating units...." (CUB/100, Jenks/6). Finally, CUB suggests that the current regulatory environment represents a marked change from the past. Historically, CUB claims, the regulatory trade-off of using first-year revenue requirement of new plants was a type of quid-pro-quo for accepting power cost increases without a PCA. (CUB/100, Jenks/3). CUB claims that since PGE now has both forward-looking NVPC rate setting mechanism (the Annual Power Cost Update Tariff[1] or "AUT") and a backward-looking PCA, the prior regulatory 'balance' has been compromised and regulatory lag now works in favor of the utility. (CUB/100, Jenks 3-4).

Q. What is regulatory lag?

[1] The annual update of rates to reflect forecast NVPC was previously known as the Resource Valuation Mechanism (RVM).

A. According to Bonbright[2], regulatory lag is:

> "…the quite usual delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or increase may be put into effect by commission orders or otherwise."

Q. Is this definition of regulatory lag important?

A. Yes, because it relates regulatory lag to levels of overall earnings. If earnings are unreasonably low, it takes time for a utility to prepare and for a commission to process and order new rates. Similarly, if earnings are unreasonably high, it takes time to process a proceeding to lower rates.

Q. Are CUB's concerns about regulatory lag stated in these terms?

A. No. CUB has written nothing about PGE's earnings or of the time it takes to process a proceeding to correct over or under-earning. While CUB suggests that PGE has created an unbalanced regulatory environment, the telling byproduct of that environment, systematic excess earnings, is absent. Table 1 below presents some key reported figures for PGE since 2001.

Table 1

Year	Authorized ROE	Earnings Test Adjusted ROE[3]
2001	11.60% / 10.5%[4]	9.65%
2002	10.50%	8.09%
2003	10.50%	7.69%
2004	10.50%	11.67%
2005	10.50%	6.64%
2006	10.50%	5.02%

[2] Principles of Public Utility Rates, pg. 96; Bonbright, Danielsen, Kamerschen, Public Utility Reports, Inc. Second Edition, 1988.
[3] Per Results of Operations Report filed with the OPUC.
[4] Authorized ROE per UE 88 of 11.60% replaced by UE 115 ROE of 10.50% on 10/1/2001.

As the table indicates, PGE's regulated ROE has exceeded its authorized ROE only once in the last six years. If PGE could systematically delay cost improvement from flowing though rates while capturing cost increases in rates without delay, PGE's financial results should be systematically better than its authorized ROE; yet this it not the case.

Q. Does the AUT and PCA minimize regulatory lag for the company while leaving it unchanged for customers as CUB suggests? (CUB/100, Jenks/3-4).

A. No. The AUT and PCA were designed to treat power costs symmetrically. That is, if PGE's unit net variable power cost (NVPC) is forecast to be lower next year than the unit NVPC forecast that is the basis of current rates, the AUT will result in lower rates next year. Likewise, if unit NVPC is forecast to be higher next year, the AUT will increase rates next year.

Similarly, if the variance between actual NVPC and forecast NVPC is negative, the PCA mechanism would tend to produce refunds. Likewise, if the variance is positive, the PCA mechanism would tend to produce customer charges. In other words, even if one accepts a more limited view of regulatory lag as Mr. Jenks advocates, the PCA and AUT reduce regulatory lag for PGE <u>and</u> for customers.

Q. Do you agree with CUB's characterization of the historical regulatory environment as only sporadically containing a PCA mechanism? (CUB/100, Jenks/4).

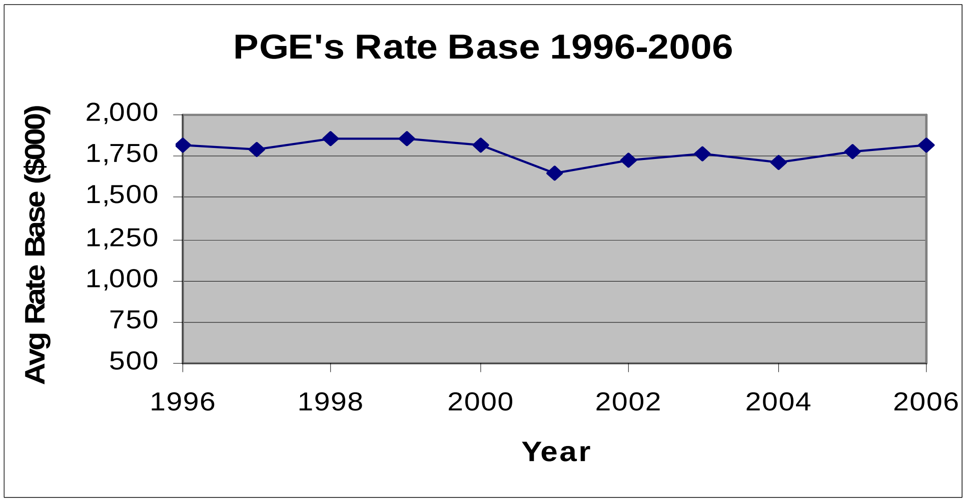
A. No. This ground has been heavily trampled in previous dockets, so we won't repeat the discussion here. (See, for example, UE 165, PGE Exhibit 300 for a discussion of the historical application of PCAs to PGE).

Q. Do you agree with CUB's characterization of the historical regulatory environment, in which PGE was granted recovery of first-year plant revenue requirement (for new plant) in exchange for managing all NVPC volatility?

A. No, that would be news to us. CUB cites no Commission order or reference for such an assertion. We believe the regulatory 'bargain' as it relates to deriving test year rate base is the expectation that the overall revenue requirement will be relatively stable over some period of time. In other words, decreases in revenue requirement due to depreciation of existing rate base will be offset by increases in revenue requirement due to future capital additions and inflation-induced increases in O&M costs.

Q. Why does it make sense to use expected embedded plant for a test year and not a forward-looking forecast of embedded plant years beyond the test year to develop rates?

A. While it is true that embedded plant will tend to decline over time due to the impact of depreciation, utilities are capital intensive and will add significant investments to their rate base annually. Thus, expanding the notion of the test year to include several years of data would require multi-year projections of capital additions, as well as multi-year projections of depreciation and O&M costs. The use of embedded plant during a test year further makes sense because capital additions and depreciation tend to balance out over time. The chart below displays PGE's rate base since 1996 (the first full year of Coyote Springs operation).



Note: 1996 and 2002 were general rate case test years. Data are from PGE's Earnings Test Adjusted Results as reported in the Results of Operations Report.

PGE did not add any new generation assets to rate base during the period 1996-2006[5], yet PGE's rate base did not systematically decline, even as the Coyote Springs investment began to depreciate in late 1995. It is for this reason that we believe it is unwise for the Commission to set rates based on expected reductions in a particular element of rate base (e.g., the levelization approach) or to authorize an annual reset of the return requirement associated with an individual plant without consideration of overall rate base, O&M costs, and earnings. To do so in isolation of other changes in costs can produce unreasonable results, such as reducing Biglow's return requirements in rates, even as overall earnings are well below authorized levels, for example because non-Biglow rate base is higher.

Q. Do you agree with CUB that generation rate base is "lumpy" and tends to decline after large additions to rate base?

A. We would agree that generation rate base is lumpy, reflecting very large investments that occur sporadically. Port Westward and Biglow Canyon 1 are good examples. However, the

[5] In fact, during the period 1996-2006, PGE retired the Bethel generating facility, sold its interest in the Centralia generating facility, and sold a partial interest in the Pelton and Round Butte project.

lumpiness of generation rate base does not necessarily translate into systematic reductions in future overall revenue requirement, in general, or rate base in particular, as the Chart above makes clear.

CUB is attempting to "cherry-pick" one element of revenue requirement (i.e., the return component of a particular plant), while ignoring other additions to rate base and the continuing effects of inflation on O&M.

Q. CUB states that PGE has been filing to bring new generating assets into rates in such a way as to eliminate regulatory lag, and to ensure that "not a day of depreciation goes by before an asset goes into rates." (CUB/100, Jenks/4). Is this the case?

A. It is certainly true that we try to align new rates with major new plant additions. To do otherwise would be imprudent from a shareholder perspective. But this is not new, as history demonstrates. The Boardman plant went on-line August 3, 1980. New rates went into effect on the same day. Colstrip 3 went on-line January 10, 1984. PGE was allowed to defer revenues associated with the plant until rates went into effect on May 1, 1984. In the order that authorized the deferral (Order No. 84-089), the Commissioner states, "Historically, when a utility completes a large generating plant, the incremental revenue requirements associated with the plant are immediately passed on to their customers through an incremental tracking increase commencing on the commercial operation date of the plant." Colstrip 4 was placed in service on April 1, 1986. While rates to recover the costs of Colstrip 4 did not go into effect until June 13, 1986, PGE was authorized to amortize certain excess collections for nuclear fuel disposal costs to offset the costs of Colstrip 4. Finally, rates for Coyote Springs went into effect November 28, 1995, just one day after the plant became operational.

In the case of Biglow's turbines, some are expected to begin generating power in October and all 76 turbines are expected to be in service by early December 2007. Yet, we are asking that rates be effective January 1, 2008. Compared against the historical standards by which new major resources have entered rates in the past, PGE's proposed treatment of Biglow is typical if not slightly delayed.

Q. CUB in fact finds a way to criticize you for accepting that regulatory lag, noting PGE's insistence that it retain dispatch benefits of Biglow prior to inclusion of the plant in rates. (CUB/100, Jenks/5). How do you respond?

A. For PGE, this is a matter of fairness. In the alternative, the dispatch benefits would flow to customers (potentially through the PCA) even though customers were not required to cover the fixed costs of Biglow. If cost reductions were processed through a rate case and were set to take effect, PGE would not expect to successfully argue that the effective date of rates to reflect that cost reduction should be postponed so that PGE can absorb some regulatory lag; yet that is what CUB would have us believe is appropriate for Biglow.

Q. Does ICNU share the same concerns as CUB?

A. To a large degree, although Mr. Falkenberg also describes an asymmetry between the use of base rates versus supplemental tariffs. Mr. Falkenberg describes PGE's approach as "piecemeal" rate making. (ICNU/100, Falkenberg/9).

Q. Is PGE's approach to rate making piecemeal?

A. No. We believe ICNU's argument is one of form over substance. We <u>could</u> have changed base energy rates for Biglow Canyon. For example, the Coyote Springs rate change to reflect the incremental impact of the plant coming on-line in 1995 was treated as a base rate change. In this case, we chose instead to use a separate rate schedule for Biglow Canyon for several reasons. The separate rate schedule was administratively simple to use. It fit well with the 2008 AUT filing, and it demonstrated our desire (and other parties as it turned out) to limit this case to Biglow Canyon costs and benefits.

The parties seem to suggest a relationship between the use of a tracker filing whereby the only change considered is the revenue requirement of a new plant (Biglow in this case) and the use of a supplemental tariff to track in that revenue requirement into rates. In fact, base rates could be updated for Biglow's revenue requirement effect.

Q. ICNU asks why PGE sought an annual update of power costs in UE 180 but would be opposed to an annual update of Biglow fixed revenue requirement. (ICNU/100, Falkenberg/12). How do you respond?

A. ICNU's question is misleading. The AUT concerns total NVPC. ICNU's proposal, however, tracks the fixed costs of only one plant. As we have pointed out previously, capital additions tend to offset the impact of depreciation when overall rate base is considered, even after lumpy investments such as Biglow Canyon. As we described in our UE 180 testimony (PGE Exhibit 400), the need for an annual update of power costs is driven by power cost volatility. Power costs can increase and (despite what parties may suggest) they can decrease substantially from year to year. The use of an annual update and a PCA mechanism is a regulatory response to volatility. CUB and ICNU are proposing annual updates to Biglow revenue requirement, yet there is no showing that PGE's overall rate base exhibits volatility of the size and effect of power costs.

Q. ICNU suggests a levelization approach to setting rates for Biglow Canyon 1. Please describe levelization in general.

A. Levelization involves calculating a fixed payment over a multi-year period that provides the same present value of revenue requirement as the expected revenue requirement of the project over the same period. Levelized cost is an analytical technique that allows comparisons of resources with vastly different revenue requirement shapes; for example, ownership versus a purchase power agreement.

Q. Has the Commission previously used a levelization approach to establish cost recovery of an asset?

A. No, not to our knowledge.

Q. Do you have any concerns with the use of levelization for rate making purposes as it relates to asset cost recovery?

A. Yes. Levelization may provide an economically equivalent outcome as setting the revenue requirement based on the annual expected cost of a resource, however, we believe there are significant regulatory policy drawbacks to this approach when applied to rate making, including:

- Opportunity to earn the Commission authorized ROE;
- Cash flow impacts to the utility;
- Inappropriate use of a test year; and
- Regulatory risk of future Commission decisions.

Q. Please describe your first policy issue with levelization, the opportunity to earn the Commission authorized ROE.

A. Levelization results in reduced customer payments today (relative to traditional cost of service revenue requirement) in exchange for a promise of higher customer payments tomorrow (again, relative to traditional cost of service revenue requirement). In setting rates, the Commission establishes recovery of prudently incurred costs for the test year with an opportunity to earn a reasonable rate of return, including an opportunity to earn the authorized ROE. If the test year alone is considered, levelization applied to recovery of a particular asset will not permit the utility to recover its prudently incurred cost and an opportunity to earn its authorized ROE *in the test year*, because the levelization approach results in less than cost of service recovery in the test year and, effectively, higher payments in periods beyond the test year. We are less than clear how levelization squares with test year rate making employed by the Commission. While the earnings shortfall in the early years <u>may</u> be addressed via the use of an accrual for a regulatory asset, this produces non-GAAP based earnings, which are generally considered of a lower quality than earnings from operations and fails to address our other concerns below.

Q. Please describe your second policy issue with levelization, cash flow impacts to the utility.

A. The cash flow impact is related to the first issue. Since levelization involves a lesser customer payment up front in exchange for larger payments in subsequent years, the cash flow of the utility is reduced up-front relative to traditional cost of service rate making and actual capital requirements, which could result in incremental borrowing needs and the incurrence of an additional capital cost.

Q. Please describe your third policy issue with levelization, inappropriate use of the test year.

A. Traditional rate making involves a forecast of normalized costs for a test year. A utility projects its O&M, rate base, and return requirements for that test year. Generally speaking, forecasts of costs beyond the test year are not considered appropriate for determining rates.

Levelization involves the use of a multi-year forecast of costs beyond the test year, including the appropriate return on equity. We are unclear why Biglow Canyon 1 revenue requirement should be levelized when we do not, for example, project post test-year capital additions and levelize the associated revenue requirement or project post test-year increases in A&G costs and levelize the associated revenue requirement.

Q. Please describe your final policy issue with levelization, the impact of regulatory risk.

A. Future Commissions are not bound by the historical decisions of past Commissions, and in particular policy perspectives can change significantly from one Commission to the next. A rate making approach that involves bringing forward expected future rate reductions in exchange for higher rates later would subject PGE to the risk that a future Commission would alter this arrangement, just when customer payments are higher than traditional cost of service would dictate.

Q. Do you have any other concerns with a levelization approach used for rate making purposes?

A. Yes. We are also concerned with the selection of an appropriate period for levelization and with potential post-2008 changes in deferred taxes associated with Biglow Canyon 1.

Q. What are your concerns regarding the choice of an appropriate period for Biglow Canyon 1 levelization?

A. Aside from the policy concern of reviewing post test year data to develop the levelized rate, this concern relates to the choice of the period of levelization. ICNU suggests a five-year levelization approach. We are concerned that the selection of the period is subject to gamesmanship since the results can vary dramatically depending on what period is selected. A couple of items will make this clear. First, as ICNU points out, Biglow Canyon 1 is subject to a five-year depreciation schedule for tax purposes[6]. Thus, deferred taxes (all else equal) would be expected to increase over the first five years of the plant's life and reverse in subsequent periods. By selecting five years as the levelization period, ICNU may be seeking to maximize the expected rate base reduction from accumulated deferred taxes while leaving out the impact of higher rate base (again, all else equal) as these deferred taxes begin to reverse in subsequent periods. Second, NEPA tax credits are expected only for the first ten years of the plant's life. It is for this reason that the graph on ICNU/100, Falkenberg/6 is misleading. The life-cycle revenue requirement of Biglow Canyon 1 is more complicated than is suggested by ICNU's graph with, for example, a spike upward in cost after year ten. Thus, a levelized approach that takes a longer period (for example 15 years) would yield a significantly different result than is suggested by ICNU. Aside from the policy issue of using multi-year periods to set rates, the selection of an appropriate period is a major factor in the result.

Q. What is your concern regarding post-2008 changes in Biglow Canyon 1 deferred taxes?

A. As previously described, Biglow Canyon 1 will have a five year MACRS schedule. PGE anticipates that future phases of Biglow will also be subject to aggressive MACRS tax depreciation. This aggressive tax depreciation, while creating a benefit, raises a concern for PGE as it relates either to levelization or an annual update of fixed costs for Biglow. Specifically, PGE could run out of tax capacity (i.e., taxable income) due to the cumulative impact of aggressive tax depreciation of wind assets and tax credits and, as a result, have currently unused tax depreciation on wind assets.

Q. Why is this a concern as it relates to levelization or annual update?

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[6] Tax depreciation is based on the IRS' Modified Accelerated Cost Recovery System (MACRS).

A. When looked at in isolation, Biglow's deferred tax liability can be expected to increase, reducing rate base. A levelization approach would assume this impact and the parties would clearly expect this impact reflected in annual updates. However, if PGE runs out of tax capacity, tax depreciation would be deferred, creating deferred tax assets (i.e., higher rate base) rather than deferred tax liabilities as would normally be expected. This is a concern regarding levelization because the standard assumption could well prove to be incorrect. It is a concern regarding an annual update because Biglow's rate base could end up higher from one year to the next due to deferred tax depreciation.

Q. Do you have a response to ICNU's analysis in ICNU/105 regarding over collections of Biglow?

A. Yes. We previously mentioned that PGE could have used base rates rather than a supplemental tariff to collect Biglow revenue requirement. In fact, the Commission could order us to use base rates rather than a supplemental tariff if they so decide. We also note that any analysis of costs beyond the test period relative to collections for the test period will show anomalous results. For example, if PGE assumes inflation would apply to its O&M costs, we could easily generate a table that shows significant under-collections relative to the test year assumptions in UE 180, for example.

Q. What is your recommendation on the policy issue before the OPUC?

A. We recommend the Commission neither update the fixed revenue requirement of Biglow annually nor use a multi-year levelization approach suggested by ICNU. Either approach is a significant change to regulatory policy. Each of these approaches attempts to address a "problem" that is, in reality, a fundamental element of cost of service rate making. While

PGE is willing to discuss rate making on a holistic basis, the proposed piecemeal approach is not appropriate.

Q. Does this complete your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the **Rebuttal Testimony of Randy Dahlgren and Jay Tinker (PGE/500) Policy** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated at Portland, Oregon, this 11th day of July 2007.

DOUGLAS C. TINGEY

SERVICE LIST

UE 188

LOWREY R. BROWN
CITIZENS' UTILITY BOARD OF OREGON
lowrey@oregoncub.org
(Paper service waived)

JASON EISDORFER
CITIZENS' UTILITY BOARD OF OREGON
jason@oregoncub.org
(Paper service waived)

ROBERT JENKS
CITIZENS' UTILITY BOARD OF OREGON
bob@oregoncub.org
(Paper service waived)

DAVISON VAN CLEVE, P.C.
MATTHEW W. PERKINS
333 S.W. TAYLOR - STE 400
PORTLAND, OR 97204
mail@dvclaw.com

STEPHANIE S. ANDRUS
ASSISTANT ATTORNEY GENERAL
DEPARTMENT OF JUSTICE
REGULATED UTILITY & BUSINESS SECTION
1162 COURT ST. N.E.
SALEM, OR 97301-4096
stephanie.andrus@state.or.us

JUDY JOHNSON
PUBLIC UTILITY COMMISSION
P.O. BOX 2148
SALEM, OR 97204
judy.johnson@state.or.us

RFI CONSULTING INC
RANDALL J. FALKENBERG PMB 362
8343 ROSWELL RD
SANDY SPRINGS, GA 30350
consultrfi@aol.com

KEN LEWIS
2980 N.W. MONTE VISTA TERRACE
PORTLAND, OR 97210
Kl05pdx@comcast.net

DANIEL MEEK
ATTORNEY AT LAW
10949 S.W. 4TH AVENUE
PORTLAND, OR 97219
dan@meek.net