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CLEARING UP

NORTHWEST ENERGY MARKETS

Energy and Utility News for the U.S. Pacific Northwest and Western Canada

Inside. . .

The Week in Summary

[1] Snake Dam Breaching Authorization In House Salmon Study Bill

Language that would give Congress the authority to ask the Secretary of the Army to breach lower Snake dams was included in a bill introduced last week in the House of Representatives that calls for more study of all salmon recovery alternatives. The bill will likely go nowhere, but the B-word is resonating throughout the region as the Aug. 14 deadline nears for the Obama administration to weigh in on the new hydro BiOp. ***Breaching studies may be added to satisfy the judge, at [19].***

[2] NW Utilities Request Their Share of Federal Smart Grid Grants

Northwest utilities have applied for almost $300 million in federal stimulus funds under the Smart Grid Investment Grant program. The deadline for applications for a share of the $3.4 billion in funds was Aug. 6. Seattle City Light has asked for the most in matching funds in the region, at $102 million; Tacoma and Idaho Power tie for second, at about $45 million each. The utilities are hoping to get federal matching funds for a variety of smart grid projects, from adding infrastructure to make them AMI-ready to speeding up ongoing deployment of AMI systems. ***Federal funds would speed up smart grid plans for all, at [13].***

[3] Wave-Energy Backers, Utilities Work To Expand Resource Knowledge

Oregon wave-energy proponents are working with Northwest utilities to expand their knowledge of this emerging energy resource and to foster its eventual application. The Oregon Wave Energy Trust's Utility Market Initiative is focusing on key utility-related issues for wave power, such as resource and technology assessments, business models and grid-integration issues. Commercial wave-energy ventures are years away, but this project is aimed at advancing understanding for utilities as well as developers in this resource's embryonic stage. ***Learning about wave power, at [14].***

[4] Publics Hate BPA's DSI Offer; Alcoa Employees Love It

BPA customers are incensed that the agency's latest offer to its two remaining direct service customers includes benefits worth nearly a half billion dollars, even as the agency is raising preference rates. This is only one of many complaints about the draft terms BPA proposed last month. Meantime Alcoa's employees and supporters deluged the agency with thanks for the offer and desperate statements about the need to retain jobs at and around the smelter. ***Alcoa's current contract expires next month, at [20], while the Ninth Circuit denies rehearing of its decision invalidating DSI monetary provisions at [21].***

Week in Summary

[5] Idaho Power Files First Oregon Base-Rate Case in Five Years

Idaho Power asked the Oregon PUC last month for a 22.6-percent, $7.3-million general rate increase to address what the company says is a long-standing mismatch in costs to serve customers there and its ability to recover those costs in rates. The base-rate request--the company's first for the state in five years--is comparable to the 21.5-percent overall increase its Idaho customers have seen in the same period. It would help the utility cover its $800-million investment in infrastructure improvements. ***The requested ROE increase would provide an additional $1.5 million of net income at [17].***

[6] Avista Asks Idaho PUC to OK Higher Conservation Riders, Lower PCA

Avista has asked the Idaho PUC to approve two conservation riders and lower its Power Cost Adjustment. In an effort to keep rate increases low because of the current economic downturn and reduce the total number of rate changes, the riders and PCA rate have already been negotiated to some extent and included in rates effective Aug. 1. They will now be reviewed separately by the IPUC. ***Putting all the rate changes in one basket at [18].***

[7] PSE to Develop Lower Snake River Wind Project

Puget Sound Energy has bought out its partner in the 1432-MW Lower Snake River Wind Project. The utility announced last week that RES Americas Inc. will stay on as the project's prime contractor, but PSE had "purchased full ownership rights" and "will oversee all development, design and construction of the wind facility, as well as its operations when in service." ***At [16], PSE's IRP indicated that the company would be getting involved earlier in the development process.***

[8] Studies Highlight Costs of GHG Reduction

There's been no shortage of studies forecasting the costs of curbing the nation's greenhouse gas emissions. Last week, the Electric Power Research Institute and the Department of Energy added to the body of work with a pair of studies highlighting what technology and resources will be needed to lower emissions and how much it's likely to cost per household. ***Big costs for a big problem at [15].***

[9] POTOMAC: Free Allowances Dampen Climate Bill Price Impacts, Study Shows

Free emissions allowances for electric and gas utilities would dampen energy price impacts of the House climate bill through 2025, an Energy Information Administration study released Aug. 4 shows. Other recently released studies indicate analyses of the economic impacts of climate legislation tend to overstate costs and overlook energy efficiency's potential to cut greenhouse gas emissions. ***Also at [22], Congress raids a third of the $6 billion in stimulus funds appropriated for renewables and transmission loan guarantees in order to keep the "Cash for Clunkers" program going.***

Briefs

[10] Portland, Seattle Among Test Markets Selected for EV Program

Portland and Seattle are among the five test markets selected in a $99.8-million project funded by the U.S. Department of Energy aimed at encouraging expansion of an electric vehicle infrastructure.

Under a grant announced Aug. 5, Electric Transportation Engineering Corporation (eTec) will partner with Nissan North America to deploy up to 5,000 electric vehicles and install 12,750 charging stations in five U.S. markets. The other markets are in California, Arizona and Tennessee.

Nissan will make up to 1,000 of its LEAF electric passenger cars available for purchase in each of the five test markets once the EV hits the market in 2010. According to Nissan, its "LEAF" zero-emission, all-electric vehicle will travel 100 miles on a single charge and be priced in the range of a typical family sedan. Charging stations are to be installed in homes, businesses and public locations, DOE said.

Participating utilities include Puget Sound Energy, Seattle City Light and Snohomish County PUD in Washington; Portland General Electric in Oregon; San Diego Gas & Electric in California; and Salt River Project and Tucson Electric Power in Arizona.

PGE has already partnered with local governments and businesses to install nearly 20 EV charging stations in the Portland-metro area and Salem. In 2008, Seattle began a pilot project to test plug-in hybrid electric cars.

The Seattle and Portland areas will each receive up to 2,550 charging stations by the summer of 2010, according to news releases. LEAF buyers will be offered a 220-volt charging station in their home at no cost under the grant.

According to a city of Seattle news release, "eTec and project partners will study electric vehicle and charging infrastructure usage to help streamline future charge station deployment across the country."

The general public will also get to test drive the vehicles, the news release indicated. Zipcar, the world's largest car sharing service, is a partner in the program; Zipcar and the city of Seattle plan to collaborate on placing LEAFs in Zipcar's Seattle fleet.

The electric vehicle funds were part of a $2.4 billion award to fund battery manufacturing, electric vehicle demonstrations, charging station installations, and EV component production across the U.S.

Another grant recipient was Johnson Controls, which was awarded nearly $300 million to manufacture battery cells and separators at plants in Lebanon, Ore., and Michigan.

Other grants include $21 million for EnergG2, Inc. to make nano-carbon for ultracapacitors at its Albany, Ore., facility; $45.4 million for the South Coast Air Quality Management District to demonstrate plug-in hybrid trucks and shuttle buses; and $22.2 million for Cascade Sierra Solutions, headquartered in Coburg, Ore., to install truck stop electrification systems so that truckers have an alternative to running their diesel engines for obtaining power ***[Jude Noland and Jim DiPeso].***

[10.1] U.S. Geothermal Completes $10 Million Private Placement Deal

Boise-based U.S. Geothermal is expecting to close on a $10 million investment from a syndicate of Canadian investment dealers that will help fund production wells at the Neal Hot Springs geothermal project in eastern Oregon near Vale.

The offering--8.1 million subscription receipts exchangeable for common stock and stock purchase warrants--is scheduled to close by Aug. 12. It will also be used to boost the company's general working capital.

The company expects the Neal Hot Springs project to be operational in 2011 and deliver a net 22 MW to the grid from a binary-cycle power plant it says will use "significantly improved technology."

The project has been selected by the U.S. Department of Energy to enter into due diligence review on an $85-million project loan expected to cover 80 percent of the $106 million estimated total capital costs (CU No. 1392 [8.2]). Construction is scheduled to start in mid-2010.

Although the company doesn't yet have a power purchase agreement for the generation, it anticipates Idaho Power will be the eventual customer. It signed an inter-connection agreement with the utility in February for a $3.2-million, 10.3-mile line designed to carry 26 MW of capacity (CU No. 1392 [10.1])

U.S. Geothermal debuted the Northwest's first geothermal project in late 2006 at its Raft River site. Idaho Power currently purchases all of the first phase's output, about 13 MW.

Generation from the second-phase Raft River project, which is expected to be completed by 2013, will be sold to Eugene Water and Electric Board via a power exchange deal facilitated by BPA. A third-phase project is slated to come on line a year or two later, depending on funding ***[R. A.].***

[10.2] Oregon EFSC OKs Non-Baseload CO2 Bookkeeping Rules

The Oregon Energy Facility Siting Council has approved Portland General Electric's petition to launch a rulemaking process that could change the state's carbon dioxide standard for non-baseload power plants to reflect actual emissions, rather than nominal full-capacity emissions.

EFSC accepted the petition at its July 31 meeting. The state's Department of Energy will conduct an informal workshop Aug. 25 to discuss language for the proposed rule, to be followed by a formal notice of proposed rulemaking and hearing.

The current rule for truing up emission forecasts requires a plant operator to report and offset emissions based on hours of operation assumed to be at full capacity. Under PGE's request, the plant could report actual CO2 emissions as directly measured.

This issue concerns the utility because it plans to build a 200-MW peaker at its Port Westward site for wind integration and load-following (CU No. 1367 [3/12]). The current true-up approach "may substantially overstate actual gross carbon dioxide emissions" of a generating unit operating at partial load conditions, according to the proposed rulemaking request PGE filed last month (CU No. 1401 [4/14]) ***[R. A.].***

[10.3] OPUC to Let IOUs Provide REC Reporting Service, For Now

The Oregon PUC has ruled that the state's investor-owned electric utilities--Portland General Electric, PacifiCorp and Idaho Power--will offer third-party renewables generators the reporting services needed to certify the green tags associated with that generation.

These so-called Qualified Reporting Entity services, provided over the next two years voluntarily per a memorandum of understanding with the utilities, will be reviewed before the second quarter of 2011. In the meantime, the docket has been suspended *[UM 1394]*.

The docket was opened Oct. 7, 2008, and a settlement filed May 8, 2009. OPUC adopted the settlement July 26.

The Western Renewable Energy Generation Information System requires such services in order to count the generation toward certified green tags, or Renewable Energy Credits, which can in some cases count toward renewable energy standards.

According to the order, BPA provides the QRE service at no cost within its balancing authority area. But outside of this, no entity provides the service to all generators who need the service in Oregon. PacifiCorp and Idaho Power are certified to provide the service, but currently only do so for their own generation resources.

Because the parties to the settlement disagree on whether the PUC has jurisdiction to order the utilities to provide QRE service, commission approval won't be requested for the agreements under which utilities will provide the service.

The service agreements for PGE, PacifiCorp and Idaho Power call for one-time set-up fees of $297, $280 and $205, respectively, and monthly fees of $59, $50, and $56 ***[R. A.].***

[10.4] IPUC to Examine Basis of Avoided-Cost Rates for Small QF Wind Projects

Spurred on by rate mismatches between small-wind Qualified Facilities and utility-scale wind projects, Idaho regulators announced Aug. 6 that they would scrutinize the way "published" avoided-cost rates are calculated for QFs with 10 aMW or less of monthly generation. Those rates are now based on a utility's estimated costs for building and operating a natural gas-fired combined-cycle combustion turbine.

The PUC has asked all three investor-owned utilities in the state--Idaho Power, Avista and PacifiCorp--as well as interested parties to comment on the adequacy of this approach by Sept. l9, 2009.

Prior to 1995, a coal-fired proxy, or "Surrogate

Avoidable Resource," formed the basis for the published rates. The order replacing this with a gas-fired CCCT *[25884]* noted that the Northwest Power Planning Council had adopted the CCCT as its "regional resource of choice," and further observed that if "the gas CCCT proves not to be a viable, cost effective resource . . . then we are free to again alter our choice of the surrogate."

In its filing for the docket *[GNR-E-09-03]*, the IPUC said it was only concerned about these issues for QFs with 10 aMW or less of generation. Rates for larger projects employ a least-cost method based on a utility's integrated resource plan.

Although the filing also says it will address the matter for all QF types, issues associated with small wind QFs have generated most of the recent utility calls to change the way the avoided-cost rates are calculated.

Avista, for example, said last month that it intends to request the IPUC adopt a wind-based SAR in this proceeding, an approach it took as an alternative to claiming QF wind project green tags that it said would help offset high avoided-cost rates (CU No. 1401 [7]) ***[R. A.].***

[10.5] Wind Forecasting Competition Under Way

A pair of companies are facing off to see which can better predict the region's wind patterns in a contest sponsored by the Bonneville Power Administration.

AWS Truewind of Albany, N.Y., and Energy & Meteo Systems of Oldenburg, Germany, this month will begin forecasting winds at four Oregon and Washington wind projects, based on 2007 conditions. Oregon State University researchers will assist a national peer review team in assessing the predictions against actual meteorological data.

The team with the most accurate predictions will be in line for a BPA contract to develop a full-scale wind forecast model for the entire fleet of Northwest wind projects.

"Wind power is a great energy source, but we could make even better use of it if we could anticipate big changes," said John Pease, the project manager overseeing the initiative for BPA's Technology Innovation Office. "By fostering this friendly competition, we're getting some of the best wind forecasting brainpower in the world focused on developing an important new tool."

The competition is a collaboration with the California Independent System Operator, which manages much of California's power grid. Some Northwest wind energy helps California fulfill its aggressive renewable energy standards.

Both companies must use the same publicly available meteorological data, including records from BPA wind measurement sites managed and quality checked by OSU.

The competing companies will deliver forecasts through December. BPA will select the winning forecast model in early 2010, and could decide to contract with both teams, depending on their strengths ***[S. E.].***

Notes & Comments

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Bearing Down

[11] This Heat Wave Is Making Me Crazy

Editor's note: This column was written early last week, when Eastern Washington was experiencing the tail end of the PNW heat wave. By deadline, temperatures had cooled off to an unbelievable 64 degrees. Various contractors still had not called back.

I'm at my desk in my home office here in beautiful, bucolic Walla Walla, and I can almost hear my electric meter spinning faster and faster, getting ready to fly off the side of the house. It's 83 degrees in here, and I have the heat pump/AC thermostat set at around 77. We're in at least the second week of 100-degree temperatures; the newspaper reported it hit 108 over the weekend, and temps are supposed to stay in the triple digits through much of the week.

In spite of the view from my office of the wide open spaces, this hot weather makes me claustrophobic. I have the shades drawn to keep the room cool, so I can't see the view anyway--and when I do look out, the horizon has that burned-out brightness that signals intense heat. It's too hot to be outdoors for more than a couple of minutes; even the dogs are staying inside, trying to stay cool by lying near the AC vents.

I can't wait to get the next bill from our power company. But while suffering the summer version of cabin fever, I've been taking action--the shotgun approach, perhaps, but at least it's something.

I contacted Current Electric, the only business in the area that installs solar PV systems, and had them come out last week to do a solar site survey of our house. I've been looking on line at heat pump prices, thinking it may finally be time to replace the 20-year-old model that's trying to keep my computer from melting. I'm also considering moving, but who would buy this energy-inefficient 1980 house with ridiculous cathedral ceilings and a loft over the family room?

I guess we're stuck here for now. And we have been following up on the list of various and sundry efficiency measures that we've collected in the 10-plus years we've lived here. Eight years ago we replaced the main floor heat pump with an efficient natural gas furnace that has a variable speed fan, two-stage burner and AFUE rating

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Price Report

Off-Peak Power Rises Slightly, Yet Markets Remain Stable, Cheap

On a recent earnings call, analysts asked Sempra Energy about low margins on trades for electricity and natural gas.

Although last year at this time Sempra's trading subsidiary benefited from higher prices, right now "we have probably some of the lowest gas prices and lowest power prices across the country that we've had in a long time," Sempra Chief Financial Officer Mark Snell said. "And that's in sharp contrast to some of the highest prices we had a year ago, so that has taken the value of volatility really out of those markets."

Snell also mentioned that "differentials across the country are about as low as they've ever been." California natural gas, which traditionally trades at a steep discount to Henry Hub, "is actually even with Henry or just a few cents above, so all of those kinds of factors have led to the power and gas business being a tough trading environment currently."

Spot Western electricity and natural gas prices the past few months have been in line with Snell's analysis. Power has been cheap-usually $30 to $40 for peak power-with gas prices around $3/MMBtu. Volatility has likewise been tame.

Last week was little different. Daytime power values spread little more than $7/MWh in either direction and gained, on average, about $2 in California hubs. Off-peak power did jump up a little more, but spreads were tight.

California prime trades, for instance, climbed about $1 to $2 at North of Path 15 and South of Path 15 to average around $40.26/MWh. Palo Verde peak prices were nearly static at an average of $38.53.

Nighttime trades did advance about $7 on average for the week at Palo Verde, NP15 and SP15 (see chart).

The slack economy continues to moderate power demand. In California, peak electricity use stayed below 40,000 MW last week and fell to 35,900 MW by Thursday, according to the California Independent System Operator.

The situation in the Northwest was a little different. The area has been recovering from a heat blast, and to add to the situation, the Columbia Generating Station in Washington was shut down Wednesday after an electrical fault sparked a fire in an overhead tray that contains electrical cables. The 1150-MW plant will return to full operation when repairs and an investigation into the fire's cause are complete.

Peak California-Oregon border prices added nearly $4 to close at an average of $43.25/MWh. Off-peak values rose $5 to average $35.15.

Average Mid-Columbia prime trades settled out the week $3 higher at $39.62. Nighttime deliveries gained $5 to average $34.10/MWh.

Working natural gas in storage vaulted to an all-time high for the end of July, closing out the month up 66 Bcf at 3.089 Tcf, the U.S. Energy Information Administration reported. Inventories are at the highest point for this time of year since the department started tracking monthly levels in 1976. Storage is running 23.1 percent higher than a year ago, and 19.1 percent above the five-year average.

Hot weather out West kept storage increases limited to 1 Bcf the week before last, leaving supplies at 442 Bcf, or 25.2 percent over last year, and 21.4 percent higher than the five-year average.

Overall, energy drillers have been closing rigs since last September, when they peaked at 1,606 because of low prices. In the last few weeks, however, natural gas rigs in operation have multiplied as producers grow a tad more confident about an economic recovery and higher energy demand. Houston oilfield-services firm Baker Hughes reported that working natural gas rigs increased by four rigs last week to 681 ***[Kristina Shevory and Chris Raphael].***

Western Electricity Prices
Week of August 3-7, 2009
($/ MWh)

	Peak	Off-Peak
Alberta Pool	7.25-52.70	7.25-30.03
Mid-Columbia	34-42	28.25-36
COB	36.50-44	29-36.50
NP15 *	35.25-40.60	24.75-33
SP15 *	35.25-40.65	24-31
Palo Verde	35.25-40	21.25-30.50

* Prices represent both day-ahead locational marginal prices (financial swaps, or EZ Gen DA LMPs) and quasi-swap prices (EZ Gen) as reported by ICE.

Western Natural Gas Prices
($/MMBtu)

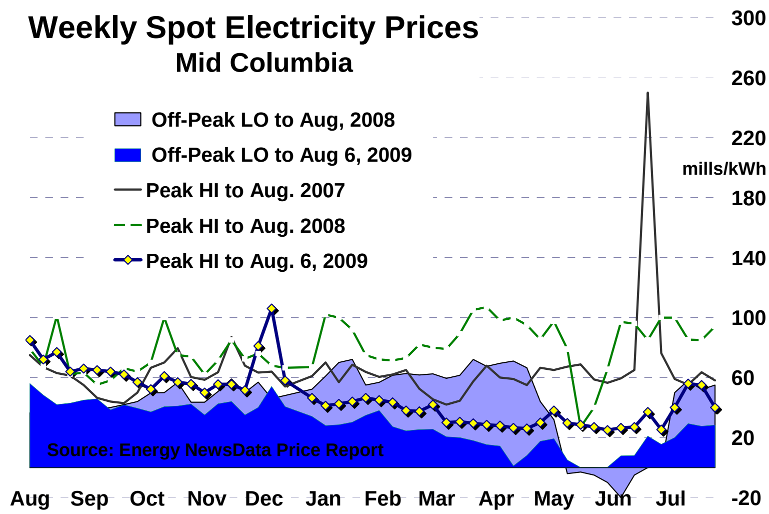
Permian Basin, Texas	3.23-3.83
San Juan Basin, N.M.	3.15-3.64
Southern California Border	3.32-3.87
Malin, Ore	3.16-3.71
Alberta Hub	2.83-2.99

Northwest Numbers

[12] Mid-C Spot Prices Register Tepid Response to Torrid Temps

Peak prices for Mid-Columbia power show significantly different trends than those of previous years, as demand remains much lower. Even with recent record temperatures in many of the heavily populated parts of the region, peak period high prices only reached levels formerly shown by off-peak prices.

The highest price for peak period power in the last three months was $56/MWh on July 24. The trading days just before and after that were the only ones this year when Mid-C spot prices hit $50 or more. In the last week of July, Seattle set three consecutive daily high-temperature records in a row, establishing a new all-time high, and prices fell consistently. Trades for Mid-C peak on the Intercontinental Exchange (ICE) have yet to average $50 or above this year.

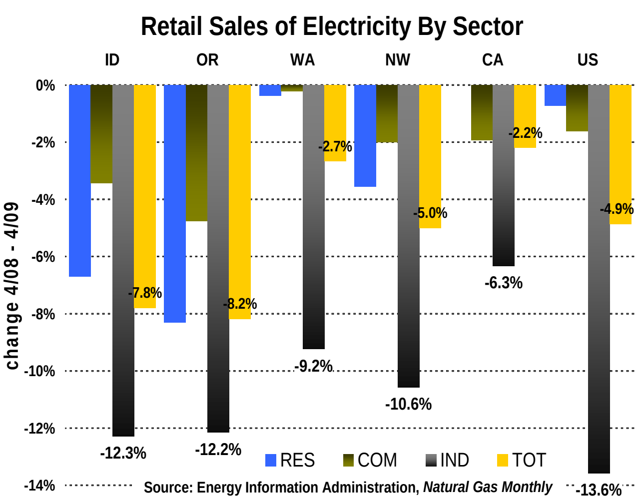


In contrast, last year at this time off-peak low prices were in the $50s (at right). Off-peak prices did not get below zero this year, but have otherwise also been much below year-ago levels. On June 4, off-peak couldn't rise above $1, trading only as high as 75 cents, with some given away at the low end that day, and an average of 24 cents on the ICE platform.

Northwest spot gas has consistently posted among the lowest prices for day-ahead supply in the nation for several weeks, ensuring low spot power prices. Although both gas and electric prices have rebounded considerably since we last looked at them here in CU No. 1392, they seem to be settling down again, suggesting that the weather-induced spikes we've seen, such as they were, may be the summer high, since the region and its neighbors have plenty of reserve power and low-cost gas in the wings.

Supply is clearly not the central issue driving spot power prices. Demand, particularly industrial demand, has cratered. The Federal Reserve reports that total U.S. industrial production fell 13.6 percent from June of '08 to this June. The EIA reports that U.S. net generation has been lower in year-over-year comparisons in each of the past nine months. April-to-April comparisons--the most recent available in the Electric Power monthly--show a five-percent decline. Coal generation has declined the most, falling more than 12 percent, while wind generation is up almost 35 percent.

The same data show overall generation in Northwest states down as well. In Oregon and Washington the decline is limited to independent power producers, with utility generation actually up slightly in both states. Consumption as measured by retail sales to ultimate consumers is down in the Northwest, most sharply in Oregon and Idaho in the snapshot comparison of April to April (left).



August is supposed to remain hot, with the Climate Prediction Center suggesting higher chances for warmer-than-normal temperatures across the entire region and most of the country west of the Rockies, except coastal California. That won't do much for spot power prices in the current environment.

There are clear signs of economic revitalization that might lead one to anticipate a rebound in capacity utilization and power use. Iron ore is going for more than it has in 10 months, and oil is holding above $70. But these signs do not point to recovery here as much as they signal changes in south Asia and China, although it seems reasonable to suspect that financial speculation there about recovery has more to do with firming commodity prices than substantial turnaround in demand.

Power prices here will remain subdued until industry rebounds. Seattle was singled out as among a handful of U.S. cities to buck the trend in manufacturing employment, adding jobs in a year-over-year comparison. Few other signs point to a resurgence in demand for commodities like electricity, yet. The view from low points in a valley is usually constrained, with trails all leading up to strenuous hikes. Perhaps that's where we are now ***[Alan Mountjoy-Venning].***

Continued from page 4

of 96.6 percent, along with a new SEER 12 air conditioner. We made those improvements back when utilities weren't offering rebates for HVAC upgrades, and those efficiency ratings were about as high as we could afford to go.

We also replaced our old washer and dryer with high-efficiency models during the pre-rebate era. Last year, we followed up with a super-efficient refrigerator--and did receive a rebate--and added as much insulation as our house could accommodate without ripping out walls.

This summer, we put in six new energy-efficient windows on the main floor, which made a much bigger difference than we ever imagined possible, since replacing windows is usually considered one of the less effective methods of improving efficiency. We've been so pleased with the better comfort level that we're considering biting the bullet and changing out the rest of the old windows. We would get a rebate for that, even if it's not much. But every little bit helps.

At the same time, we made one really big mistake. When we had to replace our roof about five years ago, we went from bad to worse: rust red to dark blue. I had my doubts at the time, but the contractor assured me that color doesn't make that much difference in terms of energy use. We've since learned that it does, indeed, make a big difference. Energy Secretary Steven Chu is now recommending white or light-colored roofs; too bad I didn't have that input five years ago.

Perhaps in penance for that dumb move, we're considering insulating our cathedral ceiling from the inside: putting insulation over the wood and covering that up with sheet rock (we never liked the wood, anyway). That will probably cost us about as much as the new roof cost five years ago. But since the main purpose is to increase ceiling insulation, maybe we'll be able to get a rebate for part of it.

Still, there is only so much we can do to make an efficient silk purse out of this energy sow's ear. So I'm also thinking if we can't reduce the amount of electricity needed to keep this place livable, maybe we can produce some of that electricity on site to offset the stuff we're taking off the grid. Thus, the solar site survey. We have fine southern exposure and western and eastern, too; the good folks from Current Electric say south and west is best, so they measured our roof in those directions.

It wasn't an easy task. We have a steep roof, and it involved climbing up there with ladders and clambering around to take measurements and readings from four different places. Next they'll input their measurements into a computer program and let me know what the chances are of producing power here.

I've always wanted to go solar, and I'm hoping with the federal and state tax credits, it just might pay off. Current Electric is supposed to provide us with the payback timeline, too.

At the same time, my husband is researching the feasibility of a home wind turbine. He's leaning toward the vertical access wind turbine as opposed to the traditional style. But I'm not sure either version would go over well with the neighbors.

While I'm waiting to hear back from Current Electric, the insulation contractor, the window installer and the heat pump people, I've spent some time on the Microsoft Hohm Web site, seeing if I can get any new strategic advice. Basically Microsoft's answer to Google's PowerMeter, Hohm was launched in late June (CU No. 1396 [5/13]).

Since my utility isn't among the four selected to test the beta version of the program, I have to fill in all the information manually. It's already taken me a lot of time, and I'm not done yet. I still have to dig up some additional information about my heating system, count all the light fixtures in the house and divide them into CFL and evil incandescent categories for each room, and fill in some other blanks. The program also wants to know how many windows and doors are on each side of my house, which direction my home faces, type of construction, foundation, and many, many more details. Frankly, I doubt the typical homeowner would have the patience or the time to fill in all the blanks.

Frankly, I doubt the typical homeowner would have the patience or the time to fill in all the blanks.

That got me reminiscing to the days when local utilities offered *real* home energy audits instead of the do-it-yourself instructions you can get on their Web sites. A utility employee would come to your house, suit up and crawl around your basement, attic, and other places to assess its current efficiency, then give you a list of actions you could take to make improvements. They even helped you arrange to get the work done.

Utilities may not be willing or able to take on such a direct role again, but it sure would be nice if somebody would. With all the federal and state rebates now available for energy efficiency upgrades, it seems like there ought to be a growing market for energy audits.

Besides providing a service to homeowners like me, the information gained from an energy audit would be even more valuable to those shopping for new homes. If a prospective homebuyer knew ahead of time that the operating cost of one home would be significantly higher than the operating cost of a similarly priced home, it's likely that he or she would purchase the more efficient home. Lenders could offer better mortgage rates or allow smaller down payments for such energy-efficient homes, too--a strategy that was tried in the 1980s but didn't seem to last.

Then there's the approach taken by the city of Austin, Texas. Late last year the city council passed an ordinance that requires energy audits of all homes 10 or more years old listed for sale in the city. The ordinance took effect June 1, according to a *UPI* news story.

What's more, the story quotes Jay Gohil, head of the Austin Board of Realtors, as saying the ordinance is "reasonably acceptable for buyers as well as sellers."

Such a requirement probably wouldn't sit too well here in the independent-minded Pacific Northwest. But it sure would be nice to have an option other than running around counting light fixtures while going crazy with the heat ***[Jude Noland].***

Supply & Demand

[13] NW Utilities Request Their Share of Federal Smart Grid Grants ■ *from [2]*

Aug. 6 was the deadline for submitting applications for federal matching funds under the Smart Grid Investment Grant (SGIG) program.

An informal tally indicates Northwest utilities applied for almost $300 million of the federal matching funds for a variety of projects ranging from basic infrastructure to final roll-out of smart meters.

The Department of Energy will be distributing about $3.4 billion in funds through the program, distributed as matching grants ranging from $300,000 to $200 million.

Seattle City Light appears to be the Northwest utility asking for the most in matching funds, at $102 million; Tacoma and Idaho Power tie for second, at about $45 million each. Avista is requesting $20 million, PSE's proposal asks for $19 million, and Snohomish County PUD wants $15 million.

All of the utilities indicate such additional federal funding would allow them to implement Smart Grid technologies more quickly than under current budgets.

In the case of Tacoma Power, receiving a SGIG would speed up the installation of two-way meters for all of its 135,000 homes and businesses from a seven-year schedule to two years, according to spokeswoman Chris Gleason. The utility has already invested $140 million in a broadband telecommunications system in conjunction with its Click! cable television network, she pointed out.

"Because of this prior investment in the largest municipal broadband system in the country, the cost of implementing Smart Grid on the Tacoma system will be relatively lower than for other utilities," Tacoma Public Utilities Director Bill Gaines said in a cover letter to Energy Secretary Steven Chu.

Seattle City Light is requesting $102 million to support a three-year, $204-million project that includes advanced meter infrastructure, as well as distribution system and substation automation, said spokesman Scott Thomsen. The muni has conducted two small pilot projects with AMI, with the goal of going from these pilots to installing AMI throughout its system. Minus the stimulus funds, "we were looking at a five-year rollout," he said.

Idaho Power's proposal requests $47 million in matching funds for an "integrated cross-cutting system," said Dave Angell, Idaho Power delivery planning manager.

DOE's Funding Opportunity Announcement for the grants included a number of different types of applications, he said--for AMI, customer, distribution, or transmission systems; equipment manufacturing, or for a combination of those. Idaho Power is doing everything but equipment manufacturing, Angell said.

Idaho Power is already installing 475,000 smart meters across its service territory, along with the communications infrastructure and meter data management systems to support it. "We're funding that program; that's our 50-percent of the match," Angell said.

The utility intends to use the stimulus funds to pay for a customer information system that would allow Idaho Power to do time-variant pricing; an "enterprise meter data mart" to which data collected by the AMI system would be transferred, and used for customer service, load research, planning and operation support; a web-based "energy usage presentation tool" that will give customers close to real-time access to energy use information; and a customer relations management system aimed at improving customer acceptance of energy efficiency and demand response programs.

Also included in Idaho Power's request is funding for an Energy Management System tool that would improve integration of renewable resources and installation of phasor measurement units--what Angell called a "transmission situational awareness tool" to assess operating conditions on the transmission system and improve reliability.

'We're funding that program; that's our 50-percent of the match.'

The final piece of Idaho Power's application is for installation of a "self-healing network" in Pocatello, involving five substations and 22 feeders, that would improve the system's automatic reclosing ability and further isolate outages to affect fewer customers. "Part of the Smart Grid is getting more intelligence out in the feeders to isolate faults to the smallest number of customers possible," he said.

Other than the Pocatello upgrade, everything the utility has proposed is in its budget, but several years out. Angell added that the utility started working on its vision for the Smart Grid in September of last year and completed the document in June, just before DOE released its SGIG funding notice. "We prepared it just in time to respond to this proposal," he said.

Avista Utilities asked for $20 million in matching funds for a $42-million project that would upgrade the electric distribution system in Spokane to reduce energy losses. The utility already has an AMI for its Idaho customers, so it's focusing on its Washington service area.

"Essentially we're going between the substation and the home," said spokesman Hugh Imhof. "What we'll do is add better transformers, upgrade wires, and basically bring the system up to the most modern standards so it will be ready to accept future technologies," he said, noting that Avista won't be going into customer homes yet "because the technology keeps changing."

Puget Sound Energy's proposal focuses on islands, said spokesman Andy Wappler: Bainbridge, Mercer, Whidbey and Point Roberts--the latter of which is actually on a peninsula, but is an island from PSE's functional perspective.

The utility is asking the feds for $19 million; the total project will cost $42 million, Wappler said, but the portion eligible for the matching grant totals $38 million.

The grant will cover connecting two-way communications systems with smart meters in 25 percent of the homes in those communities, as well as developing a full GIS system with digital maps of the utility's entire T&D infrastructure in those areas. Also in the proposal is implementing SCADA and outage management systems technology to bring automation from local substations, with the focus on reducing both frequency and duration of outages.

All of PSE's electric and natural gas customers already have automated one-way meter reading capability, Wappler said.

"This will allow us to move, in these select communities, to two-way meters," Wappler said, adding the "discrete areas" were selected because they provide the best opportunity to collect measurable and accurate data on how these technologies impact reliability of service and energy efficiency.

Wappler said the utility is also hoping to use federal funds to expand its pilot Home Energy Reports program to include customers in the four islands. While the reports don't strictly qualify as Smart Grid technology, they allow PSE to leverage those technologies, he said.

Snohomish County PUD is asking for $15.8 million in matching funds for a $31-million project that will build the infrastructure for a Smart Grid, said Mike Holcomb, assistant general manager for distribution and engineering services.

"We'll be putting in almost 1,809 miles of fiber optic cable," he told *Clearing Up*. "Snohomish is a big geographic county, so we're spread out over 2,200 square miles, and have 84 substations that all need to be hooked together."

The proposal also calls for automating those substations, "which are of varying vintages," so they can all be operated by the utility's SCADA system. SnoPUD will also automate a selected number of circuits between the substation and user, to test voltage reduction as a means of reducing loss on the system and overall energy use.

Both Snohomish and PSE have been working with Puget Sound New Energy Solutions, a consortium of Puget Sound area governments, public and private utilities, and other stakeholders working toward a common regional strategy for new energy systems that includes Smart Grid development.

The group has provided letters of support for the utilities' proposals and helped arrange support from the region's Congressional delegation, said Mercer Island City Councilmember Mike Grady, co-chairman of NES.

PacifiCorp, Northwestern Energy, and Chelan and Grant PUDs did not file grant proposals. DOE is expected to announce grant recipients in October ***[Jude Noland].***

[14] Supporters, Utilities Collaborate to Characterize Wave Resource ■ *from [3]*

Oregon wave-energy proponents are working with Northwest utilities to expand their knowledge of this emerging--but still largely conceptual--energy resource, and to foster its eventual application.

The Utility Market Initiative, established by the Oregon Wave Energy Trust, is primarily focused on business models, grid-integration tools, and examining resource and technology potential.

The initiative involves a project team led by Pacific Energy Ventures (PEV) and an advisory group made up of members from the Northwest utility community.

A project background sheet cited the importance of confronting technical and market challenges to help wave energy succeed--an effort it said "will require close collaboration between the utility and wave energy industries."

The backgrounder also said that the project seeks to "remove utility barriers and expand opportunities for wave energy to become a viable resource for Oregon and the region," and that it would "provide useful tools and effective strategies to guide the integration of wave energy into the electric grid."

John Prescott, president/CEO of PNGC Power and an OWET board member, helped spearhead the venture.

"I wanted to make sure that the . . . wave-energy technology had a good chance of becoming commercialized, and I wanted to make sure utilities were involved up front," Prescott told *Clearing Up*. "It'll be the utilities and their customers ultimately paying the cost of this resource."

PNGC already has dipped a toe into wave energy with an agreement signed in 2007 with Ocean Power Technologies to provide $500,000 toward a 150-KW demonstration installation near Reedsport, Ore. (CU No. 1276 [6.6], No. 1288 [4/16]). The two entities previously agreed on a framework for potential collaboration on a phased 50-MW wave development, with PNGC having ownership or power-purchase options.

"It's our hope that once we prove the technology and we do maybe a small pilot . . . we can start to bring the cost down and mass-produce these things," said Prescott. He noted PNGC is examining a variety of future resource options. Wave power "just happens to fit well, especially on the Oregon coast, with economic development as a side benefit."

Justin Klure of PEV described two key objectives in this venture.

"One is to develop the necessary strategic planning and policy initiatives that would help encourage the integration of wave energy into the long-term planning processes of Northwest utilities," he said. A second goal "is to focus on very specific technical tools or strategies that are required to bring early-stage or pilot projects to bear. The only way to get to hundreds of [installed] megawatts is to first be able to demonstrate a couple of megawatts."

Klure described four "viable" wave-energy ventures in play off the Oregon coast, all with FERC preliminary permits for further study and all "actively engaged in moving into the licensing process." The most advanced is Ocean Power Technology's 1.5-MW project near Reedsport, for which current plans call for one device in the water in 2010 and nine more in 2011, he said. Tillamook County, Winchester Bay and Coos Bay are other prospective wave-energy locales in this group.

Among the several tasks the market initiative is undertaking is "utility engagement," including formation of the advisory group convened by former BPA transmission executive Vickie VanZandt.

Members of the group are from Portland General Electric, PacifiCorp, BPA, Eugene Water and Electric Board, Snohomish County PUD, Tillamook PUD, Central Lincoln PUD, Douglas Electric Cooperative and PNGC Power. Representatives from BC Hydro and Pacific Gas & Electric also are participating.

This group, which is scheduled to meet four times by year's end, will provide guidance on the project's approach and products, Klure says.

One high priority of the group is gauging the wave-power resource in Oregon. Electric Power Research Institute--which has conducted what Klure called "very preliminary" assessments--is collaborating in this project on a more detailed outlook.

Also on the to-do list is getting the latest on technology. A number of potential wave-energy technologies are under development, including point absorber, pressurized seawater, oscillating water column, attenuator and pressurized hydro, but a superior technology has yet to emerge.

"From a utility perspective, they need to know the technology works and is going to be reliable," said Klure.

With resource and technology information, the market initiative will further explore wave's power-generation potential in Oregon, both energy and capacity, Klure said.

Another project topic is business models, which will look at ownership and power-purchase options, as well as such areas as price-support mechanisms, wave energy's value/cost, and development of international standards.

The project also will examine grid integration, specifically including interconnection guidelines, forecasting tools, power scheduling, telemetry and other utility technical and operational considerations.

Utilities are the "primary audience" for this venture, Klure said, but wave-energy developers also stand to benefit. He said the wave industry is concentrating largely on technology development, and "not so much" on project development and utility issues such as grid integration.

This project is scheduled to conclude by year-end 2009 ***[Mark Ohrenschall].***

[15] New Studies Highlight Challenges and Costs of Curbing Emissions ■ *from [8]*

Studies highlighting the costs of curbing greenhouse gas emissions are starting to pile up, as the Senate begins debating the climate and energy bill that cleared the House in June.

Last week, the Electric Power Research Institute added to the growing body of research when it concluded that reducing the nation's emissions by 41 percent by 2030 will require the addition of 45 new nuclear plants, as well as a four-fold increase in solar and wind generation.

In addition, 100 million plug-in vehicles will have to be on the road by 2030, while electricity consumption will need to drop by 8 percent through improved end-use efficiency measures.

The EPRI study of a "full-portfolio" scenario also assumes widespread adoption of carbon capture and sequestration technologies, both for existing and new coal-fired facilities. Most analysts agree that carbon capture and sequestration technologies won't be commercially viable until at least 2020 or beyond.

Implementing the "full portfolio" scenario would cost each household $16,000, according to the EPRI study. The "limited portfolio" scenario, which excludes CCS technology and any new nuclear facilities, would add $28,400 to ratepayers' budgets.

EPRI's study says the "full portfolio" scenario could reduce costs to the U.S. economy for emissions reductions by more than $1 trillion by 2050. However, deployment of the full portfolio scenario could result in an 80-percent increase in the wholesale cost of electricity by 2050 relative to current costs, while the "limited portfolio" model shows a 210-percent jump in wholesale prices by 2050.

'Our analysis clearly shows the imperative.'

A spokesman for EPRI wasn't available to comment for this story.

"Our analysis clearly shows the imperative for the electricity sector to move aggressively to deploy a full portfolio of technologies that will lead to a low-carbon energy future while limiting costs to the nation's economy," Steve Specker, president and CEO of EPRI, said in a statement.

On Tuesday, the Department of Energy's research arm also released a study on the cost impacts of the American Clean Energy and Security Act of 2009.

Putting a price on carbon emissions could add 20 percent to electric bills by 2030, according to the DOE's study. The study indicates that utility bills could increase three to five percent by 2020, jumping to 20 percent by 2030.

The studies released last week add to the growing body of research into the costs of lowering emissions.

In June, The Congressional Budget Office issued a forecast that the Waxman-Markey legislation, which is currently being debated in the Senate, would cost the average U.S. household $175 in higher energy costs in 2020.

In June 2008, the International Energy Agency reported that cutting GHG emissions by 50 percent by 2050 would require a $45-billion investment in solar, wind and nuclear generation, and carbon capture and storage technology.

On the West Coast the recipe for curbing emissions excludes any new nuclear facilities, and relies heavily on solar and wind generation, along with natural gas-fired generation and efficiency.

Because of state-mandated renewable portfolio standards, emission performance laws that exclude any conventional coal-fired generation and the legal and social obstacles to nuclear energy, Pacific Northwest utilities will be limited to acquiring wind and natural-gas fired generation and beefing up efficiency programs, as the main tools for curbing emissions.

A wave of solar development proposed for California and the desert Southwest may give California utilities an additional renewable energy option, but the competition among West Coast utilities for Northwest wind will help push the costs of wind even higher.

Jeff King, senior resource analyst at the Northwest Power and Conservation Council, reviewed the results of the EPRI study for *Clearing Up*.

"I think the four-fold increase in renewables isn't out of the question by 2030, given the rate of expansion in the Northwest over the last five years," King said, noting the development of offshore wind on the east coast and a major expansion of solar thermal in southwest.

King is skeptical that 45 new nuclear facilities will be developed by 2030. He says some of the 27 or so plants that are currently being discussed for development may be built by 2020, but the majority of developers will likely wait until some plants have been in operation a few years before developing more.

"Generally, I don't see nuclear in the West until, at some point, when we've got a dozen plants in the southeast or Midwest that have been running well for several years and there's some agreement reached on what to do with the spent fuel," he said. "I would be really surprised to see something move ahead in the West."

The 8-percent reduction in energy demand, if it's based on peak loads, is "plausible," King said.

The Brattle Group co-authored a recent study for the Federal Energy Regulatory Commission that estimated peak demand for electricity could be reduced by 5 percent in 2019, according to a recent story in *The New York Times*. An "achievable" scenario for demand management could knock peak demand down by nearly 10 percent in 2019, compared to current trends, according to the Brattle Group study ***[Steve Ernst].***

[16] PSE to Develop Lower Snake River Wind Project ■ *from [7]*

Puget Sound Energy bought out its partner in the Lower Snake River Wind Project and will develop the proposed 1432-MW project on its own.

The utility announced last week that it had "purchased full ownership rights" from RES Americas Inc., and that it "will oversee all development, design and construction of the wind facility, as well as its operations when in service."

RES Americas will remain the project's prime contractor. Puget expects initial construction on support infrastructure to begin in 2010, and the first phases to enter commercial energy production in 2011.

Terms of the deal were not disclosed.

The companies announced a joint development partnership on the project, which will span two counties--Garfield and Columbia Counties in Southwestern Washington--in December 2008 (CU No. 1370 [4/14]).

A conditional use permit (CUP) application for the project was filed in January 2009 in Garfield County, Wash., and the CUP is expected to be filed in Columbia County later this year.

According to the January 2009 CUP application, the Lower Snake River Wind Energy Project will have the capacity to produce as much as 1432 MW from up to 795 wind turbines.

A draft environmental impact study for the project has been filed along with the permit application in Garfield and Columbia counties.

Puget's move to develop the Lower Snake River wind farm marks the first time it has developed a wind project on its own.

RES Americas developed both of PSE's operating wind farms--the Hopkins Ridge Wind Facility, near Dayton, Wash., which opened in 2005; and the Wild Horse Wind Facility, located near Ellensburg, Wash. The company is also working on a 44-MW expansion of the Wild Horse facility.

Puget purchased both projects upon completion.

The move to buy out RES Americas' half of the Lower Snake River project may not be a complete surprise.

In the 2009 Integrated Resource Plan PSE filed last week with Washington regulators (CU No. 1401 [2/13]), Puget warned that the recent economic meltdown and tightening of credit markets was pinching wind developers.

As a result, in order to meet renewable resource requirements, PSE has entered the development process earlier than in the past and will probably do the same for natural gas generation resources, given the scarcity of independently owned resources remaining in the region, the IRP says.

'This means that PSE will be forced to take on more development risk.'

"This means that PSE will be forced to take on more development risk than in the past to meet the needs of our customers," according to the IRP.

PSE has locked up a prime piece of windy real estate at a time of increased competition for renewable resources.

Last month, Seattle City Light released a request for proposals seeking 50 MW of renewable energy (CU No 1399 [7.8]). SCL's request came on the heels of an RFP released by 11 Washington PUDs looking for 3 aMW of renewable energy to start Oct. 1, 2011, and ramping up to 105 aMW by 2028 (CU No. 1398 [1/15]).

The PUD's request also calls for 11 aMW of non-renewable energy to be delivered starting in 2011 and growing to 142 aMW in 2028.

In addition, the group wants to acquire 30 MW of summer-peaking capacity starting in 2011, as well as 40 MW of stand-alone shaping/firming services.

PacifiCorp is also looking for renewables. The company released an RFP seeking 1400 MW of new renewable resources by 2010 and an additional 600 MW by 2013 ***[Steve Ernst].***

Courts & Commissions

[17] Idaho Power Wants 22.6-Percent, $7.3M Oregon Base-Rate Bump ■ *from [5]*

Idaho Power asked the Oregon PUC July 31 to grant a 22.6-percemt, $7.3-million general rate increase to address what it says is a "long-term, substantial imbalance between the cost of providing service in Oregon" and the utility's ability to recover those costs under current rates *[UE 213]*.

The company said this base-rate request is its first in Oregon in about five years, and is comparable to the 21.5-percent overall increase Idaho regulators have approved for its customers in that state over the same period. The rate increase would help cover an $800-million investment in infrastructure improvements, the utility said.

While OPUC and Idaho Power have recently implemented a power cost adjustment mechanism to keep up with substantial power and fuel cost swings, the base rate doesn't reflect this, and has put the company "in the position of trying to catch up while building for the future," Rick Gale, VP of regulatory affairs, said in a statement. "We understand challenging economic conditions make the timing of this particular rate request difficult."

'We understand challenging economic conditions.'

The requested increase stems from electric plant additions, increases in expenses and a return-on-equity increase.

The electric plant additions totaling $600 million, after depreciation, make up $3.7 million, or 11.5 percent, of the increase request. This reflects the addition of two peakers--Bennett Mountain and Danskin 1; new construction at 21 substation sites; the addition of nearly 2,000 miles of distribution lines; and capacity expansion or new construction affecting 95 miles of transmission lines. Idaho Power's current total system nameplate capacity is 3267 MW, and was 2912 MW five years ago.

In addition, the non-power-supply expense growth has outpaced revenues in the Oregon jurisdiction since 2003, the last test year, by $2.1 million, or 6.3 percent of the rate request.

Finally, the utility has requested an increase in its current 10-percent return on equity to 11.25 percent, which would boost the revenue request by another $1.5 million, or 4.8 percent.

The proposed rate changes vary widely among the customer classes, but most have been adjusted to 3.1 percent above their individual cost-of-service levels in order to pick up the revenue shortfall from applying rate increase caps of 75 percent to Irrigation and Traffic Control Lighting service classes, and from keeping Area Lighting and transmission voltage-level Large Power services fixed to avoid decreasing them.

Residential and small general service customers would see two rate tiers. Residential and small general service customers would see two rate tiers. The company serves 19,303 customers in all classes in Oregon.

The low tier for residential customers would cover the first 800 KWh, and rates would vary by season, being highest in the high-demand summer months June through August. The proposed overall average increase for residential customers would be 37.34 percent, increasing the monthly bill from $75.47 to $110.28 in summer and to $97.12 the rest of the year.

The small general service rates would see an overall rate increase of 41.16 percent, a low tier that spans the first 300 KWh, and fixed rates throughout the year.

Secondary level large general service customers would keep the current single-tier rate structure, and rates would be increased 9.8 percent, while primary and transmission level large general service customers would have seasonal time-of-use rates with an overall 22.19-percent increase.

Primary- and secondary-level industrial service customers would see an 8.75-percent overall increase in rates, while the transmission-level service customers would see no rate change at all.

Finally, agricultural irrigation service rates would increase overall by 44.69 percent, with seasonal load-factor pricing during September and June through August, along with a higher energy rate in these months for the first 164 KWh, and lower rates for all other hours.

The PUC has 10 months to rule on the request ***[Rick Adair].***

[18] Avista Asks IPUC to Increase Conservation Riders, Lower PCA ■ *from [6]*

Avista has asked the Idaho PUC to approve increases in two conservation riders and lower its Power Cost Adjustment.

The utility wants to increase the electric conservation rider from 2.24 to 3.27 percent of customer bills, and the gas rider from 1.55 percent to 2.6 percent *[AVU-E-09-06, AVU-G-09-04]*. The riders fund conservation programs and create a mechanism for a yearly adjustment each spring. The current filings were made in late June; the commission issued a request for comments July 31.

The rider increases are already part of the 1.5- and 1.2-percent electric and gas rate increases, respectively, that the IPUC approved July 17, per settlements in the general electric and gas rate cases *[AVU-E-09-01, AVU-G-09-01]*. The changes took effect Aug. 1, but the riders are still subject to a hearing process that could ultimately lead to revisions.

IPUC included them in the new rates along with the new, lower PCA surcharge to avoid having several changes to rates throughout the year.

Under terms of the electric rate case settlement, the PCA implemented Aug. 1 *[AVU-E-09-07]* defers recent power cost recovery to the future to help mitigate the rate increase as an aid in the recent economic downturn (CU

No. 1395 [4/18]). As a result, the PCA surcharge rate of $6.10 per MWh implemented Oct. 1, 2008, was lowered to $3.44/MWh. This lower rate is expected to stay in place until at least Oct. 1, 2010, when the rates proposed in Avista's next annual PCA will be implemented.

Avista had originally proposed lowering the PCA rate to $2.57/MWh when it was seeking a larger 12.8-percent base-rate increase, rather than the 5.7-percent increase reached through the settlement. Customers would have had a net 7.8 percent increase in rates; under the settlement, the net increase is 1.5 percent.

Approval of the conservation riders would increase annual revenue by $5.4 million as pass-throughs that don't affect the company's earnings. Revenue collected from the riders can be used only to fund ongoing programs, and to pay off shortfalls in the electric and gas rider funds of $2.36 million and $1 million, respectively.

The riders fund more than 30 programs in demand-side management and energy efficiency that rely on financial incentives or rebates to encourage customer participation.

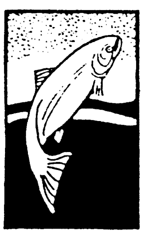
The programs also include renewable technologies and sustainable building measures. Avista has also encouraged the direct use of natural gas by its electric customers with rebates for the conversion of electric to natural gas space and water heaters.

Avista says it continues to exceed targets in electric and gas savings as the result of these programs for its Washington and Idaho customers.

More than 110 aMW of DSM programs are now in place on the company's total retail average load in 2008 of 1100 aMW. Gas savings in 2008 amounted to 1.9 million therms, 136 percent of the company's target.

The utility is also proposing to reduce large swings to the rider through annual adjustment filings around Feb. 15 ***[Rick Adair].***

Environment



Fish

[19] House Bill Would Give Congress OK to Breach Snake Dams

■ *from [1]*

With the Obama administration expected to announce its position on the 2008 hydro BiOp by this Friday, a last-minute PR blitz by BiOp critics has spilled over into proposed legislation that calls for more study of "all" recovery options for Columbia Basin salmon--"all" being the code for breaching lower Snake dams.

The latest flap came after Washington Rep. Jim McDermott (D) introduced a new version of his old salmon planning bill July 31 that includes a provision giving Congress the authority to breach the dams.

The current 10-year salmon plan doesn't include any possibility for breaching those four dams because federal attorneys had argued that it was not an action reasonably certain to occur.

Most critics of the plan disappeared--except for environmental and fishing groups, the state of Oregon and the Nez Perce Tribe--after BPA promised some Columbia Basin tribes and states nearly $1 billion in salmon recovery money in exchange for supporting the plan and promises not to stump for dam removal over the next 10 years.

McDermott's bill--the latest version of proposed legislation he has championed for years--calls for a scientific analysis of all salmon recovery efforts, including dam removal, to be provided by the National Academy of Sciences.

None of McDermott's previous efforts at putting the salmon recovery study into law has made it out of committee, and there is no reason to think that his latest effort will fare any better.

It has already incurred the wrath of another Washington congressman, Doc Hastings (R), who vowed to stop it.

"One of first places this dam removal bill will land in Congress is on my desk as the top Republican on the House Natural Resources Committee, and I pledge to do everything in my power to stop it," Hastings said.

Congressional support is waning for McDermott's salmon legislation. He has only 21 co-sponsors this time around. In 2007, he had 32 co-sponsors. In 2005, 76 other representatives co-sponsored the proposal.

According to the bill's language, "Recent studies indicate that the window of time to protect and restore Snake River salmon and steelhead is short, with scientists estimating that, if changes do not occur, several of the remaining Snake River populations could be extinct within the next 20 years."

Two years ago, in his letter soliciting support from other politicians, McDermott said the fish could be extinct in 15 years.

The bill language doesn't cite any particular study to back up its claim, but it is likely based on a largely discredited 2001 analysis funded by the environmental group Trout Unlimited that cherry-picked data to reach its conclusions.

But earlier this year, the extinction theme was picked up by the federal BiOp judge, James Redden. Last May, at a non-public meeting between litigants, he made continual references to the possibility of the Snake River salmon going extinct by 2017, shortly after an article in *High Country News* dredged up the 2001 study (CU No. 1385 [11]).

The federal government's latest salmon plan disputes that notion, and says most ESA-listed runs are "trending towards recovery."

In fact, the region is poised to see the real possibility of a record run of ESA-listed Snake River spring chinook next year, if this spring's astounding jack counts are any indication.

That hasn't stopped McDermott, his allies at Taxpayers for Common Sense and other politicians from making another run at it. Only one other Northwest politician has expressed support for the proposed legislation, Oregon Rep. Earl Blumenauer (D), who issued his own statement after the bill was introduced.

"Some have equated knowing the facts with actually triggering the process to remove the dams," he wrote. "My position over the years has been consistently to support evaluating all options for salmon recovery. The studies authorized by the bill will help us determine the consequences of dam removal not only for Northwest salmon, but also for transportation, energy, and irrigation in the region."

Blumenauer didn't mention the huge effort completed by the Corps of Engineers in 2001 that looked at different alternatives for fish passage on the lower Snake, including dam breaching, and considered social and economic consequences as well as expected biological benefits.

The six-year, $20-million study found--to no one's surprise--that the agency preferred to make major system improvements at the four dams, rather than tear them out.

The drastic breaching alternative had originally come to light after an interim review found that partial-year drawdowns of reservoirs behind the dams would cost more and probably help fish less than simply breaching them and paying the economic price.

By 1999, the Corps had narrowed the range of alternatives to three others besides breaching: existing condition, maximum fish transport, and the major system improvements.

Nearly 9,000 people attended meetings throughout the Northwest to discuss the options. The Corps collected 230,000 written comments before it was all over.

Nearly 10 years ago, the 2000 NMFS hydro BiOp called for resolution of these questions and for dam breaching studies to begin if listed fish runs didn't improve. But it also concluded that even if survival through the hydro system were 100 percent, return rates would be too low to maintain the runs, so the BiOp recommended extensive off-site mitigation efforts to help fish--especially in the first year of their life.

But Judge Redden threw that BiOp out because many of those habitat actions were non-specific and funding for them was not guaranteed.

Since then, the listed runs have generally improved, and until the latest court challenge, the dam breaching issue had been simmering.

Glenn Vanselow, executive director of the Pacific Northwest Waterways Association, said that in two previous attempts at pushing the salmon planning legislation, McDermott had even removed language that gave Congress authorization to have the dams breached.

But with the Obama administration just days away from reporting its position on the BiOp to Judge Redden, Vanselow says the breaching language in McDermott's bill is probably just a way to get more visibility for the option.

Vanselow was confident that the administration had no reason not to support the BiOp because it was based on a general collaboration throughout the region and on sound, up-to-date science.

If the Obama administration supports the BiOp, Vanselow said, the judge may be convinced that it is not just a political product based on Bush administration policies, as critics have portrayed it, but a science-based recovery plan built on unbiased analysis.

Environmental groups were still trying to paint the hydro BiOp as a product of Bush-era thinking last week. On Aug. 5, the Save Our Wild Salmon coalition orchestrated the release of a letter written by three former Northwest governors that called on President Obama to dump the current salmon plan and begin settlement talks with all parties. Downplaying the BiOp's collaborative nature--most states and tribes in the Columbia Basin support it--former governors Mike Lowry (Washington), Cecil Andrus (Idaho) and John Kitzhaber (Oregon) said they think the judge will find it illegal and recommended the administration begin settlement talks with all parties.

Environmental groups were still trying to paint the hydro BiOp as a product of Bush-era thinking.

"Dialog among key parties on the salmon, energy, water and jobs issues at stake here has never entirely died," the letter said, "but it was not a priority for the last administration. Bringing people together to find lawful, science-based solutions that help people, create jobs, and build the green economy of tomorrow is a priority for you, and it is exactly what is needed in this case."

Sources said that White House officials met again with NOAA personnel on Aug. 6 in Washington, D.C., to discuss elements of the BiOp, with updated information from NOAA scientists.

No one wants to bet just how far the new administration will go to please Redden. Some say the White House may actually support NMFS' own studies that contradict the judge's court-ordered spill regime. The scientists say the added spill in May short-changes survival of Snake spring chinook and steelhead because it reduces the number of juvenile fish that are transported downstream by barge.

Redden had suggested that before he would approve the 2008 BiOp, it would need more spill at dams, and more habitat improvement actions, particularly in the estuary, along with a provision to study other recovery alternatives, like breaching the lower Snake dams if the listed stocks didn't improve.

Action agencies are reportedly working feverishly on a contingency plan to satisfy the judge, and it will most likely include some language that calls for the Corps of Engineers to initiate breaching studies in case listed fish populations don't stay in recovery mode.

Some sources tell *Clearing Up* that the White House, which is actually convinced the current BiOp is scientifically sound, will still do most everything it can to placate the judge, whether based on the best science or not, because they feel if this BiOp goes down, any BiOp could go down.

If Redden does approve the BiOp, plaintiff groups may still appeal his decision if they feel they can get even more concessions in the future.

If breaching studies end up as part of the final deal, it does raise one question–just what did BPA get for the $1 billion it spent on states and tribes to keep the breaching issue out of the BiOp equation? ***[Bill Rudolph].***

Clearing It Up

[20] Publics Dislike BPA's DSI Offer; Alcoa Employees Love It ■ *from [4]*

Bonneville's preference customers have once again come out strongly opposed to a deal the agency wants to offer its two remaining aluminum Direct Service Industry customers.

Also as before, an impressive number of Alcoa's Intalco smelter employees and their supporters filed comments in support of the deal.

Most of BPA's other constituents, including the investor-owned utilities, did not file comments. Of the 200-plus comments filed, BPA estimated about 130 were from Alcoa employees or local business interests. At least one Washington state senator, Dale Brandland (R), wrote in support of the deal.

Public agencies repeatedly complained that BPA did not offer a credible business case for the offer. Many noted in their comments that the 9th U.S. Circuit Court of Appeals emphasized BPA's obligation to operate under "sound business principles" in its December opinion rejecting the monetization of the DSIs' benefits.

Customers reminded BPA that it has no obligation to offer the DSIs a contract, and implored it not to do so. They complained the terms will require BPA to pay a "subsidy" of up to $432 million to Alcoa over the next seven years, with the possibility of up to $185 million more if Columbia Falls Aluminum signs a similar contract. BPA has said it hit an impasse in its negotiations with CFAC, whose future remains cloudy.

The Public Power Council said BPA's approach will "almost entirely remove the take-or-pay and liquidated damages provisions"--terms that PPC said represented "significant and unreasonable risk" to BPA and its preference customers, and which the agency as recently as June said it would not accept.

Publics and various individuals also expressed disgust with the idea of providing benefits to a company as large and profitable as Alcoa. They are wary there is no provision to prevent Alcoa from reselling power.

On July 17, BPA asked for comment on a draft "term sheet" under which it would offer Alcoa a seven-year deal providing 285 aMW the first two years--enough to operate two of its three pot lines--at a cost not to exceed $48/MWh, and 320 aMW during the following five years at a cost not to exceed $64/MWh.

Alcoa had previously said it needs a minimum seven-year term to keep Intalco viable. BPA said the net cost for the two-year portion would therefore be capped at $82 million and for the five-year portion at $350 million--BPA's cost to obtain the power minus Alcoa's payments under the Industrial Power rate.

The proposal was BPA's latest iteration of a long-term DSI offer. Last December, BPA proposed to provide Alcoa 240 aMW for 10 years and 160 aMW for the following seven years, which it said would cost $65 million annually. In May, Bonneville asked for comment on whether to up the total amount of DSI service to 460 aMW.

Alcoa's existing amended block contract provides 390 aMW in monetized benefits at an annual cost of $39 million, but expires Sept. 30, 2009. Alcoa was due to meet with BPA this week to discuss the status of the offer, in hopes of signing a new contract in time for BPA to acquire resources before the current upward trend in prices threatens the term sheet's cost caps.

Comments on behalf of preference customers were filed by the Public Power Council, Western Public Agency Group, Northwest Requirements Utilities, PNGC, Industrial Customers of Northwest Utilities, Idaho Consumer-Owned Utilities Association. A handful of individual utilities also filed comments, including Canby Utility, Douglas Electric Co-op, Grays Harbor PUD, Springfield Utility Board, Idaho County Light & Power Co-op, Franklin PUD and Snohomish PUD.

'These arrangements reflect an unfair and unjustified policy.'

SnoPUD did not specifically say it opposed the deal, but offered suggestions to ensure the contracts are "well-constructed."

WPAG, whose two dozen members include Washington PUDs, co-ops, municipals and mutuals, said "the proposed sale cannot be justified on policy or legal grounds.

"To be consistent with sound business principles, BPA must demonstrate that a proposed discretionary sale of power to Alcoa produces demonstrable benefits to BPA, and inferentially to its preference customers that are paying for the power cost subsidy being provided to Alcoa," WPAG added. "BPA has failed to either articulate or demonstrate such benefits."

"These arrangements reflect an unfair and unjustified policy of forcing preference customers to shoulder higher power rates so that BPA can pay Alcoa or other DSIs to keep their plants operating," PPC said in its comments. "PPC's members will in turn be required to pass on those costs to homes and businesses during one of the worst recessions in memory."

Canby Utility demanded BPA issue a record of decision to explain how the transaction comports with the "sound business principles" required in the Transmission Act.

BPA issued an economic analysis showing the deal will result in "a small net gain" of 152 jobs. Customers called this estimate "highly suspect" and out of date; WPAG said even if it is accurate, it is not a legally sufficient justification. "BPA is a power marketing agency, not an employment agency."

The analysis actually shows that the increase in DSI jobs "is likely to be essentially offset" by non-DSI job losses elsewhere in the region, WPAG added. "This means that the proposed transaction is merely shifting jobs from one preference utility service area to another."

Intalco plant manager Mike Rousseau defended the deal. He said under "the terms of service that form the basis for BPA service" to the publics, industrial customers of public utilities "will receive more favorable terms, at more favorable rates" than those BPA is offering the DSIs--$27.40/MWh for 20 years of firm power, compared to $34.60/MWh for 7 years of partially interruptible service linked to market prices.

'BPA is a power marketing agency, not an employment agency.'

Rousseau argued that "BPA has a sufficient amount of surplus power" that could be used to serve the DSIs and pointed out that DSI loads have been declining while public loads have been increasing.

"Thus, increases in BPA power purchases are required to meet growing preference customer loads, not diminishing DSI loads," Rousseau said.

This echoes Alcoa's assertion in a related legal brief. "Basic economics holds that the growing preference customers' loads are the root cause of BPA's increased costs," not diminishing DSI loads, Alcoa argued.

However, a clause dealing with the treatment of such power found in the recitals of the proposed DSI contracts suggest that BPA, at least, thinks the acquisitions are to meet DSI load: "It is BPA's intent to treat acquisitions of power by BPA in support of sales to Alcoa under this Agreement as Federal Base System Resource replacements."

ICNU said BPA shouldn't increase the amount of power offered to Alcoa while raising rates to preference customers, and should not increase the amount offered to Alcoa if CFAC curtails. ICNU also objected to a number of the curtailment provisions.

Alcoa's Rousseau wrote that the curtailment section is "critical" to any agreement.

"The provision results in a balanced contract where BPA may impose take-or-pay obligations, where Alcoa's curtailment rights are limited to two curtailments, not exceeding 24 months in total duration and where BPA has no obligation to compensate Alcoa for the excess value of power during any such curtailment," Rousseau said, adding that Alcoa can't seek third-party suppliers during curtailment.

Rousseau encouraged BPA to dispense with terms under which BPA can impose environmental costs such as a carbon tax or renewable portfolio mandate on Alcoa through a mechanism other than rates.

Although Alcoa would have the right to terminate if such costs were imposed, this would "come at the cost of closure" of the plant. He said BPA has ample authority "to fully allocate unanticipated costs" in a rate proceeding.

He also urged BPA to reject preference customer assertions that providing power to smelters at less than a market price would violate the discretion accorded it by the Ninth Circuit.

"Alcoa strongly urges BPA to reject this illogic . . . To fail to serve Intalco and CFAC at the IP rate during the current severe economic recession and in the face of BPA's surplus would not only fail to meet Congressional intent in enacting the three regional preference statutes, but would constitute an abuse of BPA's discretion" ***[Ben Tansey].***

[21] Ninth Circuit Denies Rehearing in DSI Monetization Case ■ *from [4]*

A panel of the 9th U.S. Circuit Court of Appeals last week denied motions filed by BPA and Port Townsend Paper, and supported by Alcoa, to rehear its Dec. 17, 2008, decision invalidating the monetary benefit provisions of BPA's 2006 contracts with direct service industries Alcoa, CFAC and Port Townsend [PNGC I].

The panel did not explain its reasoning for the denial, and made a number of edits to the December ruling that were not explained. The edits affected the court's discussion of Section 838g of the Transmission Act, which was a focus of petitions for rehearing.

The denial comes months after the original ruling--in part because earlier this year, the court appointed a mediator, Circuit Judge Edward Leavy, to discuss the possibility of a settlement. After meeting separately with the parties, Leavy concluded "the chances of settlement were so remote that it would not be productive to continue mediation efforts," according to a joint report the parties filed May 1.

The court did slightly amend the order, removing one of the opinion's more colorful observations. The original opinion said the Residential Exchange Program is an "exception that proves a general rule--and the rule is that Congress intended BPA to operate as a business selling power for profit, not as a charitable institution distributing 'benefits.'" It changed the last part of that sentence to say only that Congress intended BPA "to operate with a business-oriented philosophy."

The panel also had second thoughts about what it means to encourage the "widest possible diversified use of electric power," a phrase contained in Section 838g of the 1974 Transmission Act that echoes the intent of the earliest preference clauses.

"BPA's first argument--that helping the DSIs furthers its mandate to 'encourage the widest diversified use of electric power'--does not justify a sale of power at below market or statutorily mandated rates," the court wrote in the original opinion. But in the amended order, it removed the next two sentences, which read, "This explanation is undercut, first of all, by the fact that the subsidized rates are supplied to just three firms, all of which use electric power for the same industrial purpose--smelting aluminum. Thus, the payments do not encourage 'diversified' use of electric power, but targeted use."

BPA and Alcoa still believe the court had a "misapprehension" about the application of Section 838g, inasmuch as it also stated that selling power to only one of BPA's three "native" customer classes would be "antithetical to achieving the 'widest possible diversified use'."

The court has yet to rule on a related case *[PNGC II]*, in which preference customers challenged the short-term "follow-on" contract amendments BPA signed with Alcoa and CFAC after *PNGC I*. BPA maintains the monetary benefit provisions in the amendments address the court's criticisms in *PNGC I*. That case was argued last month ***[Ben Tansey].***

[22] POTOMAC: Free Allowances Chill Lower Bill Price Impacts, Study Shows ■ *from [9]*

Free emissions allowances for electric and gas utilities would dampen the energy price impacts of the House climate bill through 2025, an Energy Information Administration (EIA) study released Aug. 4 shows.

In five of six scenarios the EIA examined, electricity prices in 2020 would be 3 to 4 percent above business-as-usual.

By 2030, however, prices would increase at a higher rate, reflecting the legislation's phase-out of free emissions allowances for utilities and an increase in allowance prices, the analysis concluded. By 2030, electricity prices would be 19 percent above business-as-usual in EIA's base-case scenario. Increases would range from 10 to 77 percent across the six scenarios.

Energy Secretary Steven Chu said the bill's overall cost to households, counting energy efficiency programs, would average $83 per year by 2030, which he said amounts to only 23 cents per day.

The base-case scenario assumes that low-emission generation would be deployed without serious obstacles and that use of emissions offsets would not be hindered by high costs or stringent regulations.

The House bill, passed June 26, requires reductions in greenhouse gas emissions from capped sources of 17 percent by 2020 and 83 percent by 2050.

The bill initially would distribute 85 percent of emissions allowances for free, including approximately 40 percent to electric and gas distribution utilities through 2025, with mandates to pass through the allowances' value to customers through lower rates and energy efficiency programs. Between 2026 and 2030, free utility allowances would phase out and utilities needing additional allowances would have to buy them.

Counting impacts on energy bills and higher energy prices, EIA estimated that per-year household consumption, a measure of consumer economic activity, would fall between $26 and $362 by 2020, and $157 to $850 by 2030.

EIA estimated that emissions allowance prices would range from $20 to $93 per metric ton by 2020 and $41 to $191 by 2030. Cost estimates are expressed in constant 2007 dollars.

Allowance price estimates are linked to the availability of emissions offsets, the study pointed out. In the base-case scenario, "domestic abatement of covered gases represents only 39 percent of cumulative compliance," the study said.

The DOE announced two loan guarantee solicitations last week**,** one for renewables and another for transmission infrastructure. The Aug. 5 releases include an $11 billion solicitation for lending authority to facilitate up to $30 billion in renewables loan guarantees, and $750 million in lending authority aimed at transmission infrastructure such as underwater cables, high-voltage DC lines, and lines to offshore energy generation projects.

Most of the renewables funds--$8.5 billion--would come from existing Fiscal Year 2009 appropriations. The $2.5 billion balance--including $500 million for "cutting edge" biofuel projects--and the transmission project funds would come from the $6 billion appropriated for loan guarantees in the American Recovery and Reinvestment Act enacted earlier this year.

The full $6 billion is not currently available, however. Congress raided $2 billion of it last week to bolster the popular "Cash for Clunkers" program, which offers rebates of between $3,500 and $4,500 toward the purchase of higher mileage cars in exchange for underperformers.

The supplemental "clunker" funding measure, H. R. 3435, won House approval July 31, and Senate approval Aug. 6. It was needed because consumers took only a few days to run through the original $1 billion authorized for the program, which was signed into law June 24 and launched July 24. The new funds will stay on the books through September 2010, but are expected to be exhausted by the end of this month.

The Senate passed Fiscal 2010 agriculture appropriations legislation Aug. 4 that budgets more than twice the funding for rural energy programs that was mandated in the 2008 farm bill.

The bill, which passed 80-17, budgets $68 million for rural energy, on top of the $60 million mandated in the farm bill. The money is to be used for energy efficiency and renewable energy projects on farms and at rural small businesses.

The House agriculture appropriations bill, which passed July 9, provides $20 million on top of the mandatory $60 million. Differences between the House and Senate bills will have to be worked out in a conference committee before Congress can adopt final legislation.

Dividends would be a less costly way of protecting consumers from energy price increases linked to greenhouse gas emissions caps than giving free allowances to electric and gas distribution utilities, a think tank researcher told the Senate Finance Committee at an Aug. 4 hearing.

The committee is exploring allowance allocation issues as a prelude to the Senate debate over climate legislation expected to take place when Congress re-convenes after Labor Day.

The climate and energy bill that passed the House June 26 allocates approximately 56 percent of allowances to electric and gas distribution utilities, low-income consumers, and home heating oil customers.

The House bill's emissions allowance allocation scheme would protect households with the lowest 20 percent and highest 10 percent of incomes, but burden households in middle-income ranges, Dallas Burtraw, a researcher with Resources for the Future, said. Burtraw also serves on a California advisory committee on implementing the state's greenhouse gas emissions reduction law.

If three-fourths of the value of allowances that the bill allots to utilities, low-income, and home heating were instead delivered directly to consumers as dividends, costs of implementing the bill for the average household would fall $106 per year, Burtraw estimated.

Studies probing the economic impacts of climate legislation tend to overstate costs and overlook energy efficiency's potential to cut greenhouse gas emissions, the American Council for an Energy-Efficient Economy (ACEEE) concluded in a study released July 30.

In a somewhat similar report released last month, the business consulting firm McKinsey & Company said the U.S. could reduce non-transportation energy consumption 23 percent below business-as-usual projections by 2020 by adopting cost-effective efficiency measures, but only if policies are adopted to break down persistent barriers to acquiring efficiency resources.

ACEEE said typical models of the House climate and energy bill project that total national energy costs would increase nearly 17 percent in constant 2007 dollars by 2050. ACEEE said its model, which builds in greater energy efficiency benefits that are based on historical data, indicates that 2050 energy costs would fall more than 35 percent.

Greenhouse gas emissions would fall from the current level of 8.379 billion metric tons of carbon dioxide-equivalent to 1.212 billion, the study estimated. Energy efficiency would account for 47 percent of the reduction, the study added. Typical studies estimate that efficiency would yield less than one-third the savings of ACEEE's model, the report said.

"U.S. economic performance over the last several decades demonstrates that energy markets and consumer behaviors are more dynamic than is commonly assumed," ACEEE researcher Chris P. Knight said.

McKinsey's study estimated that potential end-use efficiency in non-transportation sectors totals 9.1 quads, which would yield gross cost savings of $1.2 trillion.

Acquiring the estimated efficiency potential would require an additional $50 billion per year for 10 years, four to five times higher than 2008 spending, McKinsey estimated.

To overcome barriers such as lack of information and high up-front costs, McKinsey recommended a broad portfolio of strategies to "unlock the full potential of energy efficiency."

A system benefit charge of 0.59 cent per kilowatt-hour of electricity and 11.2 cents per therm of natural gas over 10 years could supply all of the $520 billion needed to capture the estimated efficiency potential, McKinsey said.

Richard Newell, an energy economist from Duke University, was sworn in Aug. 3 as head of the Energy Information Administration.

Dr. Newell spent 2005 as the President's Council of Economic Advisers' senior economist for energy and the environment. He has worked at Resources for the Future, and has served on National Academy of Sciences expert committees studying energy research and development, innovation prizes, and energy efficiency ***[Jim DiPeso].***

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