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Nuclear

DOMINION WEIGHS BUILDING NUCLEAR PLANTS AT EXISTING SITES IN VIRGINIA

Dominion Generation Thursday said it is considering building nuclear plants at its existing Surry and North Anna nuclear plant sites in Virginia and may submit early site permit applications to the Nuclear Regulatory Commission by year's end.

Each site has two reactors and could accommodate two more, the company said. The site permits could be banked for 10-20 years before Dominion applied to build a specific reactor, and the permits would limit the issues any opponents could raise to actual reactor licensing.

Dominion plans to make a decision on whether to go forward at one of the sites by the end of the year. Eugene Grecheck, Dominion's vice president of nuclear support services, said the company estimates it would take 12 to

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Financial

CON EDISON SECOND-QUARTER NET INCOME IMPROVES 46.4% TO $100.7M

Consolidated Edison Thursday reported second-quarter net income of $100.7-million, up 46.4% from a year before, on total operating revenue of $2.11-billion, up 3.4%. Earnings per share rose from 33 cents to 48 cents, on average basic shares of 212,115,000, up 0.07%, and diluted of 212,555,000, up 0.2%. A year before net was cut about $19.1-million by nonrecurring charges including a $15-million reserve set up for potential liability to customers from the outage at the Indian Point-2 nuclear unit. Results also reflect rate cuts in New York on Oct. 1, 2000 and April 1, 2001. Electric revenue rose 0.05% to $1.53-billion, as utility service territory sales went up 2.8% to 13,439 GWh. Gas revenue improved 23.6% to $305.4-million, with firm sales and transportation up 3.2%. Nonutility revenue slipped 2% to $185.2-million.

Operating expenses rose 1.4% to $1.9-billion, led by a 161.4% jump in income taxes, to $86.7-million. Fuel was up 7.7% to $46-million and purchased power 1.8% to $806-million. Maintenance fell 9.2% to $116.3-million and non-income taxes 6.8% to $256.5-million. "Other

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SOCAL ED FIX STILL IN DOUBT AS CALIF. LAWMAKERS CONTINUE TO SPAR OVER LEGISLATIVE PROPOSALS

Two Democratic leaders in the California Assembly were continuing to fight Thursday to keep alive legislation they introduced last week designed to prevent Southern California Edison from declaring bankruptcy.

The Assembly was expected to vote on the bill (AB 82xx) at press time Thursday after Assembly Speaker Robert Hertzberg and President Pro Tem Fred Keeley, the bill's sponsors, huddled for several hours with Democratic colleagues in an effort to get a majority behind the measure.

Although the bill has the backing of a number of Democrats, supporters became worried that it might not win a majority in the chamber after Democratic Assemblyman Rod Wright joined with Republican Keith Richman to introduce an alternative proposal (AB 83xx) earlier this week.

Both bills passed the Assembly Energy Costs and Availability

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APPA: FERC OVERSTEPPED AUTHORITY BY INCLUDING MUNICIPAL UTILITIES IN WESTERN MITIGATION ORDER

Public power groups Thursday said the Federal Energy Regulatory Commission exceeded its authority when it ordered municipal utilities to participate in its June 19 West-wide market mitigation plan.

In separate requests for rehearing, wholesale generators and traders also argued that FERC's soft price caps will only worsen the region's supply shortage.

In the June order, FERC broadened a market-mitigation plan it earlier imposed on California's market to the entire West and to all hours of the day. The plan also forced all generation owners—including municipal utilities that are not under FERC's jurisdiction— to offer all available generation into real-time markets.

The American Public Power Assn. told FERC that it has no basis to exert authority over municipal utilities, and is unnecessarily prompting a jurisdictional dispute while it attempts to mitigate the flawed wholesale market.

"APPA finds the commission's arguments mystifying," the group said in its rehearing request. "FERC argues that because it needs to regulate non-jurisdictional utilities on the same basis as [investor-owned utilities] to ensure an effective price mitigation program…it must have authority under the Federal Power Act to so regulate non-public utilities. We see no support for this

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FERC SAYS NEW MONITORING CENTER ALLOWING IT TO KEEP CLOSER EYE ON WHOLESALE MARKET

The mock trading floor the Federal Energy Regulatory Trading Commission opened two weeks ago to give it a better understanding of the wholesale power market and allow it to keep a closer eye on market behavior is already paying dividends, Chairman Curt Hebert said Thursday.

"Not only are we watching [the markets], but we're seeing the effects of our orders and rulemakings," he told reporters making the first public tour of the facility at commission headquarters in Washington.

The commission's Market Observation Resource Center is designed to give FERC near-instantaneous access to data on transmission constraints, spot prices, market commentary, and weather forecasts that will allow it to be better informed as it shapes market monitoring practices, the chairman said.

"We can identify problems and communicate with people and say, 'Here's something we see'," Hebert said. The center will allow FERC to "step in earlier" to correct perceived market flaws, he added.

The center is a part of FERC's desire to have a stronger presence in the market being criticized California officials for failing to act sooner on the state's problems. Although Hebert said the center would not have prevented blackouts in the state had it been operational last year, he said it would have given FERC the opportunity to correct market flaws as they happened, or shortly thereafter.

The center is modeled after electricity trading floors like those operated by energy wholesale giants Enron and Dynegy. After sending a number of staffers to Houston last December, FERC spent $610,000 to build the room that has eight computer workstations outfitted with 20 information services.

The computers have access to such paid services as FriedWire and Bloomberg, and the rotating staff of at least five staff members, who monitor the Websites of independent system operators in California, New York, New England, and PJM. The center also tracks weather forecasts published by EarthSat, and uses gas storage estimates by energy consultant Pira Energy Group.

"The goal is to get a feel for the market, get a context for the market," Scott Miller, director of energy markets, said.

Miller said the center proved its worth last week when the it tracked a brief price spike in the Northeast that saw wholesale energy prices soar to $700/MWh. Miller said the staff noticed the spike and immediately called ISO officials in New York and New England, who told him the spike was a result of a software problem and complications with a generator ramping up power. Before this center was launched, getting that information could have taken weeks, Miller said. Now, "we got an explanation within a few hours," he added.

COLORADO UTILITIES, GENERATORS ASK PUC TO SIMPLIFY OR ABOLISH RESOURCE PLANNING

Utilities and independent generators in Colorado Thursday asked regulators to eliminate or simplify the state's Integrated Resource Planning process, saying it stifles flexibility.

The Colorado Public Service Commission, citing changes in the electric industry, is considering modifying rules that govern power-supply planning and acquisition. The commission currently requires utilities to use a competitive bidding process to acquire resources needed over a six-year period. Since 1993, state utilities have been asked to file an IRP every three years and must obtain PUC approval of their competitive bids.

The PUC in February finally approved Xcel Energy's 1999 IRP, under which the utility added 2,000-MW of new generation and supply through a competitive solicitation. All the new generation will be peaker plants, a company spokesman said.

Xcel wants the PUC to drop the requirement that it approval all bids, arguing that the process is too time consuming. In addition, the company said the six-year timeframe for resource planning inhibits the utility from considering large, baseload plants that may take longer than six years to build.

WestPlains Energy, a UtiliCorp unit, also recommended a simplified planning process. The current rules create "a long, expensive and burdensome process that is too inflexible to permit jurisdictional electric utilities to respond adroitly to changing wholesale market conditions and retail customer demands," WestPlains told the PUC.

The Tri-State Generation and Transmission Assn. and the Colorado Coal Mining Assn. called for the outright abolishment.

But not everyone believes the IRP needs to be changed. The Land and Water Fund of the Rockies, an advocacy group, is urging the PUC to keep the process intact to maintain public input. The group believes without IRPs, utilities could under-invest in the regulated portion of their business in favor of higher returns on their unregulated business.

The PUC expects to propose new IRP rules, but no schedule for doing so. The next round of IRPs starts in 2002 and any changes would likely be made by then, a PUC spokesman said.

AEP, UTILICORP, AQUILA SEE BIG 2Q GAINS

American Electric Power, along with UtiliCorp United and its Aquila unit, Thursday predicted big gains in second-quarter profits. AEP sees "ongoing" earnings per share of 87 cents to 89 cents, up from 48 cents in second-quarter 2000, and higher than the FirstCall analysts' consensus of 71 cents. AEP still sees this year's EPS at $3.50 to $3.60, and is "comfortable they will be in the upper range despite the implementation of electricity price caps in the West and uncertainty regarding the economy," said AEP Chairman and President Linn Draper in a statement. On Thursday, AEP stock gained 9 cents to $47.51, up 41.8% from a year before. It plans to report results July 24.

Driven by gains at the 80%-owned Aquila, UtiliCorp expects EPS of $1.20-$1.25, up from 31 cents a year before, and far higher than the FirstCall consensus of 37 cents. This includes a 50 cents/share gain on the April 2001 initial public offering of 20% of Aquila.

Aquila sees EPS of $1.05, up from 25 cents a year before, and more than double the FirstCall consensus of 36 cents. EPS for 2001 is now expected to be $2.25-$2.36, versus the analysts' consensus of $1.55-$1.62. Aquila attributed the gains to strong customer interest in risk management solutions, 1,070 MW of capacity added this year, and commodity marketing. Aquila plans to report Aug. 8 and UtiliCorp Aug. 9.

On Thursday, UtiliCorp stock gained 52 cents (1.6%) to $31.95, up 49.5% from July 19, 2000. Aquila gained 77 cents (2.9%) to $27.22.

GROUP TOUTS DISTRIBUTED POWER BENEFITS, IDENTIFIES OBSTACLES YET TO BE OVERCOME

After more than a year of examining the pros and cons of distributed power, a collection of energy industry officials last week released a report highlighting the regulatory changes that need to be made for distributed power technology to reach its full potential.

And that potential is a significant benefit to the nation's power grid, concluded the Consumer Energy Council of America's Distributed Energy Forum. The consensus opinion of the 60 forum participants was that distributed power can be a benefit now, especially with restructuring issues being tackled and the likelihood that major upgrades of the nation's electric grid will not take place any time soon, said Charles Curtis, chairman of the forum.

But, before there is any widespread acceptance of distributed generation, there will have to be some leadership shown by regulators, lawmakers and utilities, Curtis said at a recent press briefing in Washington. CECA defined distributed power—which it termed distributed energy or DE—as a power source located at or near the customer and providing at least 10 MW of power.

In its 158-page report, CECA recommended new rate structures and business arrangements between host utilities and DE customers; higher priority for federal research, development and demonstration of DE technologies; adopting a consensus on standards for connecting DE systems to the grid; clear authority to allow utilities to own DE systems, whether located on the grid or on customer premises; and various actions by local, state and federal authorities to address barriers to deploying DE systems.

Utility ownership of distributed generation facilities can be a sticking point for some market players that seek to adhere to the principle of separating generation and distribution assets. "They contend conflicts of interest will arise if [utilities] are allowed to own affiliated DE assets or, at least, are not required to structurally separate DE activities to ensure arms-length transactions that prevent discrimination against unaffiliated DE providers," the report explained.

That mindset can be seen in Texas, which prohibits utilities from providing DE services, according to Curtis. While some utilities see DE as a better way to serve customers, others are inclined to disagree due to competitive and reliability concerns, Curtis said.

The consensus of the forum, however, is that "utilities should be allowed ownership rather than being barred from it" because the benefits of distributed power are so great, he said. The report noted that utilities and "many manufacturers contend that utilities will be one of the best early customers of DE technology, helping to create a market and a basis of experience in DE."

GAO TELLS CHENEY TO DELIVER ENERGY TASK FORCE DATA OR RISK CIVIL ACTION

The General Accounting Office has given Vice President Cheney a two-week deadline to submit information on his energy task force or face civil action. The issuance Wednesday of a demand letter by the congressional investigation agency marks the first time GAO has ever taken such action against a vice president.

"To date, our request for access to records necessary to do our work has been denied by your office," GAO Comptroller General David Walker wrote Cheney.

GAO has been seeking information on who the task force met with and what was discussed since April 19 when Reps. John Dingell (D-Mich.) and Henry Waxman (D-Calif.) first brought their concerns to the agency about how Cheney's group developed its energy strategy.

The July 18 letter asks Cheney to provide the names and titles of everyone who attended task force meetings, the agenda of the meetings, the companies represented at the meetings and how the task force determined whom it would invite to the meetings.

Dingell and Waxman believe that energy industry officials close to the administration played a large role in developing the plan.

GAO also asked Cheney to detail how much the White House spent to develop the strategy. The vice president sent 77 pages of financial information to GAO last month, but the office described the documents as "miscellaneous records."

The law requires that "if full access to the requested records is not granted," GAO told Cheney, "you must furnish a description of any information withheld and state the reasons for withholding the information."

Waxman and Dingell urged the vice president to provide GAO with the information. "The White House should simply try telling the truth on the task force's activities and stop hiding information that Congress and the public have a right to see," Waxman said in a statement.

"The vice president should tell his office to end this arrogant and unnecessary confrontation with GAO and accept the fact that he and the president are accountable to the Congress and the American people."

MORE GROUPS GO TO COURT TO FIGHT GPU-FIRSTENERGY MERGER, RATE ACCORD

Two more groups have gone to court in Pennsylvania to oppose both the merger of GPU and FirstEnergy and a rate settlement that accompanies that agreement. The Pennsylvania Public Utility Commission already approved the merger—which now hinges on a ruling in New Jersey—but Citizen Power and the Clean Air Council are asking the Pennnsylvania Commonwealth Court to overturn that decision.

The Clean Air Council is worried that FirstEnergy—which owns coal plants in Ohio and western Pennsylvania—will increase its output to supply GPU, which divested all of its generating plants. Because prevailing winds blow from west to east, this could degrade air quality in Pennsylvania and make it difficult for the state to meet federal ozone standards, the Philadelphia-based group stated.

Citizen Power, based in Pittsburgh, is also concerned about the rate settlement. When GPU sold its plants, the company committed to buy power for non-shopping customers in the open market. It did not, however, sign long-term contracts, and when high gas costs drove up wholesale power prices, it was caught buying expensive power to supply customers at capped rates. It lost $42-million last year and expects to lose at least $250-million in 2001. GPU wanted to recover that from ratepayers, but the PUC was not inclined to break the rate caps, so the company reached a settlement that lets it defer losses through 2010 and buy them down if and when wholesale prices fall below the capped rates.

That plan, however, jeopardizes non-utility generators (NUGs), according to Citizen Power economist Roger Odisio. Under an earlier settlement, he explained, GPU agreed to pay the NUGs "stranded costs" to cover the difference between their contract rates [to sell power to the utility] and market rates. The new rate agreement disrupts that accord because it lets GPU use those funds to pay off the market losses instead. He could not estimate how much in NUG stranded-cost payments could be affected.

Odisio also fears the rate impact if New Jersey regulators reject the merger, because the rate accord is contingent on a final merger agreement. If the deal falls apart, the Pennsylvania settlement will allow GPU to collect all of its market losses from June through the end of the year—an amount he said could run $150-million. After 2001, the company could continue to recover losses beyond the rate caps, he warned.

FACING HIGHER PRICES, MORE RESIDENTIAL CUSTOMERS SAY THEY'D SWITCH SUPPLIERS

Increasingly dissatisfied with utility prices, more than 20% of residential customers outside California—3% more than last year—said they will switch to competitive power suppliers if given the opportunity, according to a survey released Wednesday by J.D. Power and Associates.

In California, 33% of residents said they would switch suppliers, the survey found.

Although the percentages were relatively modest when customers were asked if they would take advantage of retail competition given the opportunity, seven out of 10 those polled in the latest survey said they believe their states should support electric utility competition.

"With the awareness of the California power crisis relatively high, and energy prices expected to increase, consumer loyalty is eroding and support for retail competition is growing," the company said.

The survey also found that 75% of respondents outside California believe that there is enough power to meet electricity demand in their region, but only 49% of Californians think there is sufficient supply to meet demand. The survey also noted that residents in Idaho and Washington are concerned about power supplies, while customers in Mississippi, Oklahoma and North Carolina expressed confidence in their states' supply scenario.

Still, most residential customers favor building more power plants, J.D. Power said. Fifty-one percent of those surveyed outside of California support building more power plants, while 38% favor cutting back on electricity consumption. In California, 57% back new generation and 33% prefer increased conservation.

Residential customers in 39 out of the 42 states polled expressed strong criticism of their electric utility on all aspects of price and value, the survey said. Customers reported their average monthly electric bill to be $104, up 18% from 2000, and 61% of all respondents said they expect higher electric bills next year. Residential customers' satisfaction with operational performance improved again in 2001, the survey found. Significant gains were reported in areas of power quality and reliability, billing and payment and customer service.

MISSOURI REGULATORS VACATE ORDER APPROVING KCP&L RESTRUCTURING PLAN

Hours after Missouri regulators approved Kansas City Power & Light's restructuring proposal, the regulators unanimously vacated the ruling and ordered the company to submit information on new power plant development plans.

Missouri regulators, unhappy KCP&L failed to brief them earlier this month about plans to construct a new coal-fired generating station, have ordered the utility to make an "on-the-record" July 27 presentation about the project.

After learning from the news media of plans by Great Plains Power, a KCP&L deregulated affiliate, to build the Weston Bend I coal plant, the Missouri Public Service Commission voted 3-0 on July 12 to vacate a 2-1 decision only a few hours earlier to approve a KCP&L restructuring plan.

KCP&L several months ago unveiled the details of the restructuring it promised after a merger with Western Resources fell apart in January. The company said it would form a holding company that would have three subsidiaries: a competitive generation company, a regulated electric utility, and an unregulated unit.

Great Plains says Weston Bend I would generate between 500 and 900 MW of electricity. The facility, which would be the first new coal plant built in the region in more than 20 years, would be operational in 2005. "They want additional information," a PSC spokesman said of the commission. "They didn't receive any information with regards to that" at a July 5 meeting with KCP&L representatives.

In its order for the July 27 presentation, the PSC said, in particular, "the parties shall be prepared to advise the commission as to why this [West Bend I] project was not mentioned at the on-the-record presentation" on July 5, "and whether this omission constituted a breach of the duty of candor to the tribunal. It is expected that all other material issues, not previously disclosed, will be discussed at this time."

KCP&L officials could not be reached for comment.

MD. DEVELOPER WINS LOCAL APPROVAL TO BUILD 520-MW GAS-FIRED PLANT IN VA.

Competitive Power Ventures, Silver Spring, Md., Thursday said the Fluvanna County, Va., board of supervisors has granted the company a special-use permit to build a 520-MW, gas-fired merchant project.

CPV's initial application for the permit had been rejected by the board in February, but the independent power company revised its proposal by, among other things, scrapping plans to use low-sulfur oil distillate as a backup fuel, and increasing the amount of water-storage capacity at the plant site.

CPV also proposed to make an extra $18.8-million in payments to Fluvanna County, beginning with $500,000 each year of the two-year construction phase, followed by annual payments of at least $375,000 over the plant's first 30 operating years.

A spokesman said the company plans to begin construction in the second quarter of 2002 and to hopes to bring the plant on-line in the third quarter of 2004.

CPV in June announced plans to build a 780-MW, gas-fired merchant plant in Smyth County, Va. That project, which needs no county approvals, also is expected to come on-line in about three years.

MORE COMPLETE STUDY BY FERC OF 'SIZE AND SCOPE' OF RTOs NECESSARY: NARUC

Concerned about the implications of recent federal orders urging the creation of a few, large regional transmission organizations, state utility commissioners plan to send a petition to the Federal Energy Regulatory Commission asking it to launch an investigation into optimal size and scope of RTOs.

Meeting in Seattle Wednesday, the National Assn. of

Regulatory Utility Commissioners board of directors approved a resolution calling on FERC to collect evidence and give state commissioners an opportunity to comment on the "appropriate size and geographic scope of RTOs." NARUC urged that the analysis include consideration of the costs and benefits of the RTO configurations on load centers and power markets, according to the resolution's proponents. It also advocated a more complete consideration of existing transmission lines, and existing and proposed generation in the various RTO proposals

The electricity committee passed the resolution on a 12-8 vote Tuesday. The original resolution included asking FERC to refrain from approving specific boundaries for RTOs before completing the investigation, but that language was taken out by the board, staff said.

Proponents from the West and the Southeast questioned the impact of the FERC RTO order, which favored the development of four RTOs nationwide—one each in the Northeast, the Southeast, the Midwest and the West. FERC's RTO orders last week for the Southeast and Northeast included two 45-day mediation conferences before administrative law judges for parties involved in creating transmission groups in those regions. Another order reaffirmed the commission's April 26 order on RTO West and reminded the organization of what information it must bring to FERC by December, including a plan for resolving "seams" issues, Canadian participation, a framework for a West-wide RTO, and a status report on a timetable for creating a single RTO.

Richard Hemstad of the Washington Utilities and Transportation Commission, who offered the NARUC resolution, said an evidentiary proceeding is necessary to "look holistically at what is to be the optimal configuration for RTOs."

Electricity committee members who opposed the resolution believe it could slow the process of moving forward with regional transmission organizations. "The resolution has the potential to slow the process down," said Indiana commissioner David Ziegner. "With respect to the Midwest, we don't want to see process slowed down."

ONTARIO SUCCESSFULLY COMPLETES 'DRY RUN' OF COMPETITIVE ELECTRIC MARKET

Ontario's Independent Electricity Market Operator said Thursday that it has successfully completed a six-week simulation of wholesale and retail competition, bringing the province "one step closer" toward formal implementation of competition by next May.

An IMO spokesman said that his organization "ran a simulated, open wholesale-electricity market based on real supply and demand conditions from mid-May until the end of June," and that the test—which involved the IMO and 19 market participants—was "a resounding success."

The so-called "uncoupled, operational dry run" called for operating the market "based on the real supply and demand conditions of the day," the IMO said. In addition, more than 50 specific market scenarios were "added to the mix to ensure that virtually all possible market conditions would occur during the six weeks."

Ontario initially had planned to implement wholesale and retail competition in November 2000, but in June 2000 it put off that planned start date, citing concerns about the readiness of computer and other systems. In April 2001 the provincial government said it now plans to implement competition by May 2002.

CORRECTIONS:

A story in the July 19 *Electric Power Daily* on American Electric Power's plans to expand the capacity of its Trent Mesa wind farm in Texas by 20 MW contained incorrect cost information. The planned expansion is expected to increase the project's total cost to $160-million.

In the same issue, Duke Energy International's intends to invest $480-million, not $700-million as the story indicated, in its three new gas-fired power plants and its existing hydro generation facilities in Brazil in 2002.

NUCLEAR-SITES *(continued from page 1)*

14 months to prepare a site application, which means an application could be submitted in first quarter 2003.

He said the company believes the NRC staff could complete an ESP application review in a maximum of 18 months. NRC staff, however, said at a commission briefing yesterday that it would need at least two years to conduct the review.

Word of Dominion's plans comes shortly after Exelon said it may submit an early site application to the NRC sometime next year. No new nuclear plant has been proposed in the U.S. since the mid-1970s.

CON-EDISON *(continued from page 1)*

deductions" were $5.5-million, versus zero a year before, including a 44% drop in investment income, to $1.4-million. Long-term debt interest rose 12.2% to $98.3-million and other interest fell 24.7% to $9.5-million. Con Ed still sees 2001 EPS of $3.20-$3.30. In other second-quarter results:

Reliant Resources, in its first quarterly report since public trading began May 1, had net of $175.4-million, up 57.6%, on revenue of $9.68-billion, up 167.9%. EPS were 63 cents, on basic shares of 276,944,000 and diluted of 277,246,000. Since the initial public offering of 59.8 million shares (19.9%), the rest are owned by Reliant Energy, which plans to spin them off to its shareholders by the end of the year. After that, Resources would hold most of Reliant Energy's current unregulated operations. Net was boosted $32.9-million by a "pre-acquisition contingency gain" on Reliant Energy Europe's UNA utility in the Netherlands, from its share of SEP, that country's coordinating body for power prior to wholesale competition. A year before there were gains of $18-million on sale of a development project, and $7.4-million on debt extinguishment. U.S. wholesale energy operating income rose 19.2% to $205.4-million, as revenue jumped 1,713% to $9.36-billion, on power sales of 86,098 GWh, up 140.2%. European energy operating income slumped 63% to $9.5-million, though revenue was up 103.5% to $276.5-million, as sales leaped 236% to 9,679 GWh. Retail energy lost $3.4-million, down 72%, as revenue rose 54.5% to $36.1-million. Expenses surged 175.6% to $9.48-billion, led by a 282.5% increase in purchased power, to $4.77-billion. Fuel and cost of gas sold rose 121.7% to $4.43-billion, and general, administrative, and development 111.5% to $97.3-million. Interest expense jumped 126.6% to $19.6-million, and income taxes 125% to $85.5-million.

TECO Energy net improved 25% to $71.8-million, on revenue of $641.8-million, up 14.7%. EPS rose from 46 cents to 52 cents, on average shares of 135,670,000, up 8.2%. Expenses were up 16.5% to $535.9-million, led by a 21.4% rise in operation, to $381.3-million. Maintenance dropped 14.2% to

$37.5-million. "Other income" jumped 163% to $13.5-million, and interest 18% to $46.3-million. With tax credits on TECO Coal synthetic fuels plants, income taxes plummeted 71% to $2.5-million. By segment, net from Tampa Electric was up 6.7% to $38.1-million, on revenue of $359.1-million, up 5.5%, with power sales down 6.5% to 4,513 GWh, led by a 45.8% slump in wholesale, to 342 GWh. Residential fell 1.3%, and commercial rose 0.2% and industrial 0.6%. With the credits, TECO Coal net jumped 117.5% to $13.7-million, on revenue of $72.2-million, up 28.5%. TECO Power Services net rose 28.3% to $6.8-million, as revenue went up 55.2% to $71.4-million. At "other diversified companies," net jumped 102% to $10.1-million, on revenue of $52.4-million, up 46.4%. This includes benefits from higher gas prices for TECO Coalbed Methane and TECO Gas Marketing. TECO has revised net income reporting to include internally-allocated finance costs by segment.

TransAlta net rose 16.6% to $59.1-million (Canadian), on revenue of C$606-mil, up 89.4% from a year before. At the current exchange rate of about C$1 = 65 cents U.S., net was US$38.4-mil, on revenue of US$393.9-mil. Basic EPS were C35 cents (US22.7 cents) and diluted C34 cents (US22.1 cts), both up from C30 cents, on average shares of 168.8 million, up 0.06%. Earnings before interest and taxes jumped 45% to C$109.2-mil. Leading the way was a 239.5% surge from energy marketing, to C$38.7-million. Revenue soared 507.6% to C$1.36-billion, spurred by the volatile power market in the Pacific Northwest, and high prices. But both are going to drop, along with profits from the generation segment, due to the Federal Energy Regulatory Commission order imposing a price cap mechanism on the entire Western region, TransAlta said, significantly reducing marketing earnings for the rest of the year.

Therefore TransAlta has cut its expected 2001 earnings per share from C$1.50-1.60 down to C$1.40-1.50 (US91cents-97.5 cents). TransAlta did not change the US$29-million provision booked at the end of last year for possible non-collection of bills due from California buyers, out of a total receivable of US$58-million. Since Jan. 31, TransAlta has received US$5-million.

"The provision will be reversed upon collection of the amounts owing and when the corporation has confidence that it will not have to make any repayment of such amounts as a result of retroactive changes to trading regulations from those under which TransAlta completed its trades with California entities," the company declared.

Generation EBIT was C$58.5-million, up 6%, despite a 100.1% jump in revenue, to C$444.5-million. Production was up 11% to 8,773 GWh. TransAlta acquired the 1,340-MW Centralia, Wash., plant in May 2000, but the 670-MW unit two was out of service for scrubber installation from April to June 2001. Also, the 300-MW Wabamun unit was shut from August 2000 to June 2001. Independent Power EBIT rose 37.9% to C$12-million, as revenue rose 20.9% to C97.9-million. Production was up 11.7% to 1,740 GWh. Results reflect the sale of the 265-MW Mildred Lake plant, and operation of the 360-MW Poplar Creek plant, both in January.

Puget Energy net dipped 9% to $22.9-million, on revenue of $935.4-million, up 73.6%. Basic EPS were 27 cents and diluted 26 cents, both down from 29 cents, on shares of 86,303,000, up 1.2%. Operating expenses jumped 81.6% to $863.8-million, led by a 925.2% surge in other operations and maintenance, to $41.5-million. Purchased power was up 124.8% to $535.3-million, purchased gas 125.6% to $104.2-million, and power plant fuel 36.7% to $63.1-million. Expenses were cut $50-million by unrealized gains on contracts, under *Statements of Financial Accounting Standards 133/138*, on derivatives. Interest rose 13% to $48.2-million. Electric revenue jumped 64.5% to $719.7-million, though sales dropped 12.9% to 6,700 GWh, led by a 28.2% fall in wholesale to 2,024 GWh. But with the average sales price skyrocketing 288% to 18.66 cents/kWh, wholesale revenue surged 178.4% to $377.7-million. Residential sales rose 0.2% and commercial 12.6%, and industrial fell 24.3%. Gas revenue was up 66.3% to $163-million, though volume rose only 0.4%. Heating degree days went up 13.6% to 1,034. Other revenue jumped 1,500.7% to $52.7-million.

WPS Resources net was up 2.7% to $11.7-million, on revenue of $577.2-million, up 54%. But EPS fell from 43 cents to 41 cents, on average shares of 28,573,000, up 8.2% from 26,398,000. The latter reflects the 1.8 million new shares issued in April to acquire Wisconsin Fuel & Light Co. Wisconsin Public Service electric net was $11.5-million, up 13.9%, boosting EPS 14 cts. Gas utility net slumped 66.7% to $200,000, but higher margins raised EPS 8 cents. The higher margins reflect the Jan. 1 rate hikes of 5.4% for power and 1.5% for gas at Wisconsin PS. But that were more than offset by lower EPS of 28 cents due to a 54.3% jump in operating expenses, to $558-million. EPS were also cut 22 cents by a 77.8% slump in other income, to $3-million, due to lower earnings on the nuclear decommissioning fund, and a year-before gain on the sale of a combustion turbine. With tax credits on WPS Power Development synfuels plants, tax benefits were $4.6-million, versus $1.5-million of expenses a year before.

ALLETE net fell 33.8% to $42.5-million, as revenue rose 35.5% to $443-million. Basic EPS were 58 cents and diluted 57 cents, both down from 92 cents, on basic shares of 73.4 million, up 5.5%, and diluted of 74 million, up 5.9%. A year before, there was a $30.4-million (44 cents/share) net gain on the $127-million sale of 4.7 million shares of common stock of ACE Ltd., acquired by ALLETE when ACE bought Capital Re Corp.—of which ALLETE owned about 23%—in December 1999. Energy Services (Minnesota Power) net improved 2.1% to $9.5-million, as revenue went up 6.5% to $147.9-million, on sales of 2,647 GWh, down 7.4%, led by a 20.9% slump in wholesale, to 543 GWh. Residential rose 3.6% and commercial 5.1%, and industrial fell 5.2%. Investment net jumped 69.6% to $17.3-million, on revenue of $42.9-million, up 60.7%. Automotive Services (ADESA) net improved 36.7% to $20.1-million, as revenue surged 70.2% to $220.8-million, with vehicles sold up 60.3% to 492,000. Operating expenses were up 37.4% to $370.8-million, led by a 40.8% jump in interest, to $21.4-million. Fuel and purchased power were up 6.2% to $56.8-million. Income taxes fell 28.4% to $28.2-million.

SOCAL-ED *(continued from page 1)*

Committee late Wednesday, with Wright's bill receiving a 12-3 vote compared to the Keeley bill's 11-9 margin. Wright and two other members offered "courtesy" votes to get Keeley's bill out of committee so it could be discussed on the floor, Assembly aides said.

The Keeley-Hertzberg bill, however, got a boost late Wednesday when Democratic chairmen of the Assembly Rules and Appropriations committees—both of whom support the bill—approved AB 82xx, sending it to the floor. Wright's bill was bottled up by both panels, giving Keeley and Hertzberg time to work on drumming up the 41 votes needed to pass the measure.

AB 82xx would modify the April 9 memorandum of understanding Gov. Gray Davis signed with SoCal Ed to make the proposal more palatable to Democratic lawmakers. The measure would pay the utility less than the $2.76-billion Davis had offered for its transmission system and would establish would establish an "Electric Supplier Claims Settlement Trust" to pay off wholesale suppliers' claims for payment for past power deliveries to SoCal Ed.

Wright's bill, however, looks to save SoCal Ed from bankruptcy by allowing the utility to pay off roughly $3.5-billion of its debt to suppliers through a surcharge on utility bills. In exchange, the company would promise to sell the state electricity from its retained generation at cost. The bill, which has the backing of Assembly Republicans, would not require the state to purchase the transmission system.

At press time yesterday, Wright's bill was stuck in the Assembly Rules Committee, where it was awaiting an assignment to the Appropriations Committee. In a piece of legislative sleight-of-hand, however, Wright Thursday gutted an existing bill (AB 50xx) already before the Appropriations panel and substituted AB 83xx's language. That bill, however, also had not moved by press time.

The political wrangling over either bill may thwart efforts to pass any measure by the Legislature's recess today. Both efforts have been criticized by consumer groups and some lawmakers as little more than bailouts of SoCal Ed. In addition, many members appear wary of rushing legislation that will likely have profound impact on the utility, its ratepayers and the state.

Although Wright's bill is believed to have more support in the chamber than does Keeley and Hertzberg's, legislative aides Thursday said members may be unwilling to support either if and when a floor vote occurs. One aide described the Legislature's continuing inability to agree on a SoCal Ed rescue plan as "another black mark" on the state's record in dealing with its power problems. "Basically, no one is crazy about any of the bills and everyone wants to go on summer recess," he said said, predicting that no bill reach the governor's desk before the month-long break.

The Senate also is having difficulty moving a SoCal Ed bill, due in large part to a lack of enthusiasm about the version before it, aides said. After an unsuccessful vote on a bill (SB 78xx) late Wednesday, the Senate Energy, Utilities and Communications Committee early Thursday passed the legislation in a 6-2 vote. The Appropriations Committee after rejecting it yesterday in 7-6 vote, later reconsidered and sent it to the floor.

Introduced Tuesday by Democratic Sen. Byron Sher, the bill also modifies Davis' April proposal by allowing the utility to issue only up to $2.5-billion in bonds to pay off its debt. That money would then be repaid through a mandatory charge on customer bills. The utility would also be required to give the state a five-year option to buy its transmission system at book value of about $1.2-billion.

Steve Maviglio, Davis spokesman, said the governor is still hoping for a bill by today to meet his Aug. 15 deadline for action set out under the original MOU. He said the governor planned to seek an extension of the legislative session to get a bill finished. Under state law, Davis could ask for an extension but could not compel legislators to stay in session.

• Pacific Gas and Electric Thursday said it has signed five-year agreements with 131 of its qualifying facilities at an average energy price of 5.37 cents per kWh. The utility also said it will pay the small generators the roughly $740-million it owes them for power delivered prior to PG&E's April 6 bankruptcy petition.

The utility said locking in an average fixed cost for future power deliveries from QFs will help it protect its customers from volatility in the wholesale power market. The 131 QF contracts represent roughly 2,950 MW. Each of the agreements with the QFs must be approved by from the U.S. Bankruptcy Court in San Francisco.

• The Federal Energy Regulatory Commission has denied requests that it reconsider a May 18 order conditionally allowing Arizona-based Duke Energy Mohave LLC to sell power at market-based rates.

In a June 18 decision, FERC rejected rehearing requests filed by PG&E, SoCal Ed and Los Angeles County, which argued the commission erred in applying the hub-and-spoke analysis when it found that Duke Mohave did not exercise market power. The two utilities claimed FERC should considered other methodologies for determining whether market power exists, while the county argued that FERC should suspend or terminate Duke Mohave's market-based rate authority until it develops a more "sophisticated" tool to evaluate market power.

The commission, however, said that while it "appreciates" the utilities and county's concerns, it is not "at this point...prepared to abandon the hub and spoke analysis."

Further, FERC said that to the extent that there may be market design flaws in California, it has addressed them in market-mitigation orders issued late last year and this year.

APPA-FERC *(continued from page 1)*

proposition in the commission's orders or in the case law cited by the commission."

APPA also renewed its call for a temporary return to cost-based rates, and urged FERC to apply price caps to wholesale deals longer than 24 hours. "The commission must ensure that all rates, terms and conditions for energy products that may not be just and reasonable."

In joint comments yesterday, the Electric Power Supply Assn. and the Western Power Trading Forum also asked for a rehearing, claiming that while the mitigation order provides short-term "political" stability, it will cause long-term harm because wholesale suppliers will be wary of doing business in such an uncertain atmosphere.

EPSA and WTPF note that the commission changed course on market participants by altering its April 26 mitigation plan that implemented the soft cap only in California during capacity shortages to its June decision that spread the mitigation throughout the West around-the-clock.

"[T]he commission's rules have become a moving target," the groups said. "Each mitigation order [April 26 and June 19] includes a different methodology and different inputs for determination of the proxy [market] clearing price. Each has spawned a series of clarifications and explanations sought by the CAISO and market participants."

The California Dept. of Water Resources, the state's primary buyer of electricity, also blasted the order. In its request for rehearing, CDWR claimed a 10% risk premium FERC tacked on to the market clearing price in California "indiscriminately imposes additional costs upon already-burdened power purchases in violation of well-established cost-causation principles."

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