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NUCLEONICS WEEK

Volume 59 / Number 31 / August 2, 2018

South Korea sticks to anti-nuclear policy despite surging power demand

The South Korean government has vowed to press ahead with its drive towards a nuclear energy phaseout despite mounting concerns about possible power shortages amid a record heatwave.

South Korea's electricity demand has been increasing to record levels due to high temperatures for the past several weeks, which have forced the country to operate more power reactors and fossil power plants.

"Electricity demand is surging due to [a] continuing disaster-level sweltering heat wave, but the country's power supplies are enough to meet demand," Jeong Jong-Young, chief of the nuclear department of the Ministry of Trade, Industry and Energy, or MOTIE, said in an interview July 27.

"There is no change in the government's push for energy transitions from nuclear and coal to renewable sources and LNG," he said, stressing there would be no power shortages.

President Moon Jae-In, who took office in May 2017, has pledged to reduce the country's reliance on nuclear power and pave the way for a nuclear energy-free era in the country before his five-year term ends in May 2022.

But the record heat that has sharply increased electricity demand has reinforced calls for turning back to nuclear power, with growing worries about power shortages.

To meet the surging power demand, the country's state-owned nuclear power operator Korea Hydro & Nuclear Power Co, or KHNP, has worked to increase nuclear output by adjusting reactor maintenance schedules.

"KHNP will work to make Hanbit-3 and

(continued on page 7)

Uranium market participants debate whether mine shutdown will raise price

Market participants disagreed whether Cameco's decision July 26 to keep its McArthur River uranium mine shut indefinitely, and buy up to 15 million pounds of uranium on the spot market by the end of 2019, would cause a spike in U3O8 spot prices.

Dustin Garrow, managing principal of consulting business Nuclear Fuel Associates, said in a July 30 interview that he foresees uranium spot prices increasing from the mid-$20s/lb today to somewhere between there and the low $30s/lb by year's end. The price could rise to about $40/lb by mid-2019, he said.

An industry consultant, who spoke on condition he not be identified due to his company's business relationships with various nuclear industry companies, said in a July 30 email: "There is excess inventory of about 150 million pounds of uranium which needs to be absorbed by the market, a process which will take a number of years." He noted that "Excess inventories are held by both utilities and suppliers."

"Cameco's decision to keep McArthur River shut takes 18 million pounds off the market annually, but this is not likely to have a substantial effect on uranium prices over the next year," he said.

"There is much excess inventory that needs to be worked off before a substantial price rise will occur," the consultant said. "While some increases are expected in the next few years, it could be more than five years before the U3O8 spot price passes the constant dollar $40 a pound threshold generally viewed as the minimum value

(continued on page 8)

Kepco no longer preferred bidder for Moorside

Korean Electric Power Corp. is no longer the preferred bidder to buy Toshiba's UK subsidiary NuGeneration Ltd., which is planning a nuclear plant at the Moorside site, but talks are continuing and focus on adopting a new financing model for the construction of the plant, government and company officials said August 1.

NuGen is seeking to develop the proposed Moorside nuclear power plant in Cumbria in northern England.

Midori Hara, a Toshiba spokeswoman, said in an interview August 1 that the company had sought an "early agreement with Kepco about the sale of its NuGen" after the Japanese technology vendor gave the Korean company preferred bidder status in December 2017.

She added that the two parties had failed to reach an agreement despite the negotiations involving Kepco and the UK and South Korean governments about a potential deal.

Kepco is continuing to hold discussions over taking ownership of the project, South Korea's Ministry of Trade, Industry and Energy said August 1.

"Toshiba notified Kepco of the withdrawal

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of preferred bidder status on July 25 so as to have opportunities for negotiation with other companies in the wake of high costs and delay in the project," Kim Jin, the chief of the ministry's nuclear exports department, said in an interview August 1.

Kim said the delay may be related to a potential change in the financial model for construction of nuclear plants in the UK. The government of the UK has said it favors use of contracts for difference, essentially a government-guaranteed price for power from new reactors, but criticism of the high prices in the initial contracts for EDF Energy's Hinkley Point C have led to calls for other types of financial support.

"Toshiba said it fully understands that Kepco needs an additional review for a new business model," Kim said, referring to what he said was the UK government's effort to adopt a regulated asset base model instead of using contracts for difference. Under a regulated asset base model, governments provide generating plant owners with regulated rates which can be adjusted to guarantee the utility covers its costs with an additional financial margin.

Most countries, including the UK, moved away from such systems when deregulating power markets.

UK Business and Energy Secretary Greg Clark said in a statement to parliament June 4 that the UK was considering taking a direct stake in the Wylfa Newydd nuclear plant project being developed by Hitachi's Horizon Nuclear Power project company, and would consider a regulated asset base model for future nuclear plant projects in an effort to reduce costs to ratepayers.

"Toshiba said it will keep talking to Kepco as a first priority," Kim said. "So the essence of the negotiations has not been changed."

The British government and Kepco held talks in London July 30 and agreed to carry out a joint feasibility study on the regulated asset model, according to Kim.

"The British government said it will grant Kepco a status that is similar to the one of the preferred bidder so as to keep consultations going with South Korea for the Moorside project," Kim said.

Hara declined to provide a more detailed reason for the end of the preferred bidder status and declined to comment on whether Toshiba is discussing the sale of NuGen with other bidders.

NuGen had initially planned to construct three Westinghouse AP1000s, with a combined capacity of 3,600 MW, at the Moorside site, which is adjacent to the Sellafield fuel reprocessing facility.

However, after Westinghouse, also a Toshiba subsidiary, entered US bankruptcy reorganization proceedings in March 2017, Toshiba announced it was withdrawing from the international nuclear plant construction business and intended to sell its NuGen subsidiary.

Kepco then entered exclusive negotiations with Toshiba over the purchase of Moorside. Kepco proposed to build two APR1400s at the Moorside site.

A Nugen spokesman declined to comment August 1.

A UK nuclear sector participant familiar with the Moorside project noted in an interview August 1 that he believed that the anti-nuclear power South Korean government under President Moon Jae-in that came to power in May 2017 had complicated the NuGen sale negotiations, as the new government had appointed new executives at the South Korean state nuclear power companies after the start of the exclusive negotiations. The source spoke on condition of anonymity as

S&P Global
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NUCLEONICS WEEK
Volume 59 / Number 31 / August 2, 2018

ISSN: 0048-105X

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Nucleonics Week is published 51 times yearly by Platts, a division of S&P Global, registered office: Two Penn Plaza, 25th Floor, New York, N.Y. 10121-2298.

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The source noted that he believed that Kepco still wished to complete the NuGen purchase but that the process had suffered a significant loss of momentum. The source said the final deadline by which Toshiba must complete the sale of NuGen was the end of the Japanese 2018-19 financial year on March 31.

Union calls for government equity stake

The UK nuclear power sector's largest trade union, the General, Maritime and Boilermakers union, or GMB, criticized the UK government for not taking a direct equity stake in the Moorside project.

Justin Bowden, GMB's national secretary, said in an email August 1 that "this latest wound by the Government to the plans for a much needed new nuclear power station at Moorside in Cumbria is totally self-inflicted."

Bowden added that the "lessons from the collapse of Toshiba should have been well and truly learned long ago: relying on foreign companies and countries for our essential energy needs is sheer folly."

— Charles Lee, Seoul; Yuzo Yamaguchi, Tokyo; Oliver Adelman, London

Dominion pleased with final form of Connecticut power procurement plan

Dominion Energy is pleased that a request for proposals issued by Connecticut utility regulators July 31 for bids on agreements to provide power to utilities in the state will allow the company's Millstone nuclear power plant to bid as a generating asset "at risk" of early closure beginning in 2022, Dominion's CEO Thomas Farrell said August 1.

Legislation passed by the Connecticut General Assembly in October cleared the way for Dominion to bid Millstone for such contracts. The company said the legislation was needed because Millstone was economically challenged and at risk of early closure. It argued that the plant should be allowed to bid in the same category as renewables such as solar and wind because nuclear power has environmental benefits, such as not emitting carbon, that should be compensated.

Connecticut regulators approved February 1 a plan that would allow the company to sell most of Millstone's output to state utilities for resale in wholesale power markets. The generation of Millstone-2 and -3, with a combined capacity of 2,194 MW, is currently sold under long-term arrangements to financial institutions such as hedge funds.

Under the procurement process, an existing generating resource cannot be credited for its zero-carbon and other environmental attributes unless it is designated by state regulators as being at risk of early closure. With such a designation, a resource can be credited for such attributes and gain competitive advantages in the procurement process. Dominion petitioned state regulators in May requesting that Millstone be so designated.

The state's Department of Energy and Environmental Protection, or DEEP, and its Public Utilities Regulatory Authority, PURA, issued June 22 for comment a draft request for proposals, or RFP, that would not have allowed Dominion to bid Millstone as an "existing asset at risk" of early closure until an "at risk time period" beginning in June 2023. The company objected that Millstone needed to be able to bid as an 'at risk' resource earlier than that date, whether or not the plant is currently losing money, because large investments would need to be made if its reactors were to continue to operate (NW, 12 Jul, 5).

On July 31, DEEP issued the final version of the RFP, in which the "at risk time period" was set to begin in June 2022, unless a bidder demonstrates to the regulator that the period should begin earlier than that.

During Dominion's second-quarter earnings call for analysts August 1, Farrell said the company is "pleased that DEEP modified the 'at risk time period.' By doing so, DEEP acknowledged that an existing resource that is determined to be 'at risk' should have all its attributes valued now."

Farrell said, "We expect Millstone to be granted 'at risk' status, which means its bids will be judged on price and non-price attributes such as carbon, economic impact and fuel security."

Bids are due September 14, "and DEEP is expected to select winners by the end of the year," he said. "Winning bidders will execute contracts with the local electric distributions companies thereafter, and receive final PURA approval early next year."

Some consumer groups and fossil-fuel companies opposed the legislation and have objected to designating Millstone as an at-risk resource, pointing to an independent economic assessment that determined the plant is operating profitably and is expected to do so for several years (NW, 21 Dec '17, 4).

NRG spokesman David Gaier said in a statement July 31: "The Millstone plant is clearly not 'at risk' certainly before June 1, 2022 — in fact, the plant has a capacity obligation through May 2023 with no hint of retirement. So once again, for Millstone to plead poverty is simply not credible."

The Electric Power Supply Association said in its July 20 comments on the draft RFP that "while EPSA opposes market-distorting subsidies of all stripes, DEEP and PURA should not consider awarding additional ratepayer dollars to Millstone — or any other generator — until they have provided plant-level, independently audited financial statements. To date, Dominion [has] attempted to play a shell game with both legislators and regulators, invoking dire rhetoric and scare tactics at every turn, without providing credible evidence to support its assertions."

The association added, "With ratepayer subsidies valued in the hundreds of millions of dollars on the line to be paid solely by Connecticut consumers, a fully transparent, stakeholder-driven process is critical, and EPSA applauds DEEP for maintaining such a process thus far."

As part of the petition process, Dominion has submitted to regulators confidential financial information on Millstone, and company officials have said that information is comprehensive and responsive to the regulators' needs.

— Steven Dolley, Washington

CORRECTION

Overall electricity demand in Japan is estimated to be 845.9 TWh in the fiscal year starting in April 2027, according to the Organization for Cross-regional Coordination of Transmission Operators of Japan. The group also estimates that electricity demand in the six-prefecture Tohoku region will shrink to 76.6 TWh that year from 78.1 TWh in the current fiscal year. The unit of measure of the electricity amounts were incorrect in the July 26 issue of Nucleonics Week.

EDF says schedule for Hinkley Point nuclear concrete depends on final design

- **EDF's Hinkley Point C on track for first nuclear concrete next year**
- **Work depends on finishing final design on 'tight schedule'**
- **Hinkley credit depended on French EPR milestones**

EDF in first-half 2018 financial results July 31 said it was on track to pour first nuclear island concrete in mid-2019, as previously noted, for the first unit at the 3,200-MW Hinkley Point C plant, but that schedule depends on completion of design work before the end of the year.

EDF said in the statement that this timeline for the EPR reactors under construction in western England will hold "provided that the final design, which is on a tight schedule, has been completed by the end of 2018." EDF has said that it expects to generate first power from unit one at Hinkley Point C sometime during 2025, although it has not given a formal startup date for unit two.

It further noted that completion of the nuclear island concrete "raft structure" just prior to the pouring of first nuclear concrete at Hinkley Point C requires a separate, specific approval from the UK's Office for Nuclear Regulation, or ONR. The raft structure serves as the support base over which first nuclear concrete is poured.

Alex Trueman, a spokesman for ONR, said in an email July 31 that ONR permission is required before the start of the concrete pour for the nuclear island. "ONR is currently in the process of completing its assessment and inspection activities to support this decision," he said.

The GBP19.6 billion ($25.78 billion) Hinkley Point C is the first new nuclear power station to be built in the UK for over 25 years.

Construction outside of the nuclear island began in the third quarter of 2016. The plant is 66.5% owned by EDF and 33.5% owned by China General Nuclear Corp., or CGN. EDF said in July 2017 that the GBP19.6 billion cost of the plant had increased by GBP1.5 billion from the original GBP18.1 billion cost estimate released in 2016.

EDF's statement July 31 that it is on target for the pouring of first nuclear concrete in mid-2019 comes at the same time as the company said in a statement July 25 that it has has delayed the scheduled fuel loading at its 1,600-MW Flamanville-3 EPR in France to the fourth quarter of 2019 from the first half of 2019 and increased construction costs for that unit by Eur400 million ($468 million) to Eur10.9 billion. Flamanville-3 is the reference plant for Hinkley Point C and government financial guarantees for the UK project are linked to progress on the French EPR.

The delay and cost increase for Flamanville-3 was due to quality issues with 33 welds at the unit, the company said in the statement.

EDF had previously said it expected to load fuel at Flamanville-3 during the summer of 2019. As recently as October 2017, it said the reactor's fuel loading and startup was scheduled for the last quarter of 2018, with a gradual ramp-up to full output through 2020.

Asked about the impact of the Flamanville-3 weld issue on the Hinkley Point C construction, Martyn Butlin, an EDF Energy spokesman, said in an email July 31 that the "construction of Hinkley Point C remains on track. The project has already benefitted, and will continue to learn from the experience of other projects."

Trueman said that ONR was "aware of the issue" of the problems with the Flamanville-3 welds and had "raised it with the Hinkley Point C site licensee, [EDF subsidiary] NNB Genco (HPC) Ltd."

Trueman added that "we expect NNB — and its supply chain — to use any learning from Flamanville at HPC, which we will continue to regulate robustly and inspect closely throughout construction."

Trueman also noted that there are "differences between the French and UK regulatory requirements for the Main Steam Line (MSL) welds at Flamanville 3 and Hunkley Point C. We believe that two key differences are the UK-specific requirements for qualified inspections of the welds and representative fracture toughness testing."

Fracture toughness is a measure of the resistance of a material to the spread of cracks.

EDF also said in its results statement that the start of construction of the pre-stressing gallery for unit one of Hinkley Point C in January 2018 was the "first project goal of the year" for the plant and evidence that the construction schedule was on track.

The "pre-stressing gallery" is a vertical concrete slab into which are placed the bottom part of the tension tendons that help anchor the reactor pressure vessel.

Credit conditioned on French operation

As part of the approval by the European Commission in 2016 for the credit guarantees that could help fund the construction of Hinkley Point C, EDF and its subsidiaries agreed that before any financial credit is put toward the construction cost of Hinkley Point C, a "period of trial operation at Flamanville-3 must be completed." This is known as the "base case condition," the EC said.

EC approval is required for projects receiving substantial government support as part of competition regulations in the European Union, which has limits on allowable state aid.

EDF agreed that the period of Flamanville-3 trial operation must take place no later than the end of 2020.

An EDF Energy spokesman in an August 1 email noted that the link between Flamanville-3's completion and the Hinkley Point C funding was not relevant as EDF had chosen not to take a direct GBP2 billion credit to help fund Hinkley Point C's construction, declining further comment.

The construction cost of Hinkley Point C will also be supported by a contract for difference, or CFD. Under the CFD funding model, the construction cost of Hinkley Point C will be financially supported by a 35-year CFD, which has an inflation-adjusted strike price of GBP92.50/MWh and rests on a government guarantee.

If the price of UK power falls below the strike price, the government will allow EDF to charge the difference to UK consumers in its bills for residential power use. If the price of power rises above the strike price, then EDF will refund ratepayers the difference on residential power bills.

Asked if the "base case condition" remained in place, Lyndsey Hannam, a spokeswoman for the UK's Department of Business, Energy and Industrial Strategy, or BEIS, said in an email July 31 that BEIS would not comment, saying this was a matter for EDF.

BEIS is the UK government department in charge of energy policy in the country and was instrumental in designing and coordinating the state aid application for the Hinkley Point C construction funding that was submitted to the EC and approved in 2016.

The UK government has said that nuclear construction under a program to build up to 16 GW of nuclear capacity in the UK by 2030 will be funded by the strike price and CFD financial model.

EDF in a statement July 3, 2017, that there was a "risk of deferral of delivery" for unit one of Hinkley Point C estimated at 15 months and a risk for deferral of delivery for unit two of Hinkley Point C of nine months. EDF estimated that the cost of this delay in total could be GBP700 million.

— *Oliver Adelman, London*

France's Astrid redesign puts Japan participation in question, officials say

France's decision to reduce the capacity of its planned fast reactor design raises questions about whether Japan will remain involved in the Astrid project, Japanese government officials said.

The French government said in a statement June 1 that the Advanced Sodium Technological Reactor for Industrial Demonstration, known as Astrid, will have its capacity scaled down from the initially planned 600 MW to between 100 MW and 200 MW to reduce construction costs and because development of a commercial fast reactor is not a high priority.

The new output is less than the 280-MW capacity of the Monju fast breeder reactor that Japan decided in late 2016 to decommission.

After it determined to decommission the Monju reactor, which experienced accidents and operating problems, the Japanese government increased its involvement in the Astrid project to help it develop a path to deploying its own commercial fast reactors that could enable the country's power companies to use plutonium they have been accumulating through reprocessing of spent fuel.

The decrease in capacity would allow Japan to "spend less" on the joint development of Astrid with France, a senior official at Japan's trade and industry ministry said on the sidelines of a meeting on fast reactors July 19.

"That means the reactor would be even smaller than Monju," raising concern that the project will give Japan little useful knowledge needed for the development of its own fast reactor design, he added.

Another ministry official — who agreed that the design change would be a key consideration as Japan makes a decision on whether to go ahead on the project with France — said, "We should be flexible in responding to the situation outside Japan."

The two officials, who spoke on condition of anonymity as they are not authorized to speak to the media, spoke on the sidelines of a meeting of a fast reactor committee at the trade and industry ministry July 19. They did not provide further information.

The committee, comprising specialists from technology vendor Mitsubishi Heavy Industries Ltd., Japan Atomic Energy Agency, the operator of the Monju reactor, and the Federation of Electric Power Companies as well as officials from the trade and industry and the education ministry, was formed in March 2017 by the trade and industry ministry to discuss the development of a fast reactor in Japan.

Under a France-Japan agreement in 2014, Japan agreed to pay an undisclosed portion of the cost to build the Astrid fast reactor, in the hopes of obtaining technical knowledge and operating experience it could use to build and operate its own fast reactor. The fast reactor is expected to operate using plutonium extracted from spent fuel through reprocessing.

Economical fast reactor

The French government expects that "the need for commercial deployment of fast neutron reactors is much less urgent, due to the current context of the uranium market," Nicolas Devictor, program manager for Generation IV reactors in the nuclear energy division at France's Alternative Energies and Atomic Energy Commission, or CEA, said during the June 1 fast reactor committee meeting. France is seeking an economical reactor, he added.

Uranium prices have been at historic low levels in the past year because of oversupply and flat demand.

The French high committee on information and transparency of nuclear safety said in a report July 27 that the future of some used fuels such as mixed-oxide, or MOX fuel, relies on the development of a series of Generation IV fast reactors. The committee, established under 2006 legislation, includes representatives of both houses of France's parliament as well as nuclear industry officials, regulators, workers, environmentalists and technical experts.

The Astrid program has a target of operating a demonstration fast reactor in France in the 2030s. Devictor said France will make a final decision in 2024 on whether to proceed with Astrid after France and Japan complete a basic design by 2019. That is a delay from France's earlier plan to decide whether to go ahead in 2019.

The Japanese government will decide by the end of this year whether to move beyond the basic design to the next several-year phase starting in 2020, according to the Japanese trade and industry ministry. The detailed design process could start around 2023, it said.

The two countries would work together on portions of the project, including overall plant systems, the design of the upper part of the reactor, the top cover of the containment and a core catcher and seismic motion-dampening structure, as well as the reactor vessel, the Japanese trade and industry ministry said in October of 2016.

The completion of the design of those components will be undertaken by JAEA and MHI from Japan and France's CEA and fuel cycle company Orano, formerly Areva, it added.

These technology companies will remain in the involved in the development of the rest of the Astrid reactor in the future.

Smaller may not be better

The reduction in the capacity of the reactor would make it hard to assess the higher heat stresses that would be seen on a larger reactor and equipment such as pipes, Hiroshi Miyano, a professor at Hosei University's graduate school of nuclear engineering and a former engineer involved in nuclear fuel design at Toshiba, said in an interview July 30.

The smaller Astrid would also mean a step back for Japan in the fast reactor development process, possibly forcing the country to build its own larger demonstration reactor in Japan rather than rely on Astrid, he added. If the French unit had retained a 600-MW capacity, he said, Japan might have been able to skip the development of a demonstration reactor and embark on the construction of a commercial one based on the Astrid operating experience.

Kazuya Idemitsu, a professor of engineering at Kyushu University, said in an interview July 30, "We shouldn't have decided to decommission Monju, because Astrid scaled back." Japan might remain involved in the Astrid project unless it develops a demonstration fast reactor itself, he added, noting that the smaller-capacity Astrid design "is better than nothing."

— Yuzo Yamaguchi, Tokyo; Joel Spaes, Paris

Iowa's capacity, wind surplus make nuclear closing more likely: analysts

NextEra Energy Resources' announcement July 27 of plans to shut its 647-MW Duane Arnold in Iowa is likely to be approved, given Iowa's relative surplus of capacity, including wind generation, industry analysts said in interviews this week.

NextEra Energy had said in January the reactor would likely be shut at the end of 2025, when the PPA expired.

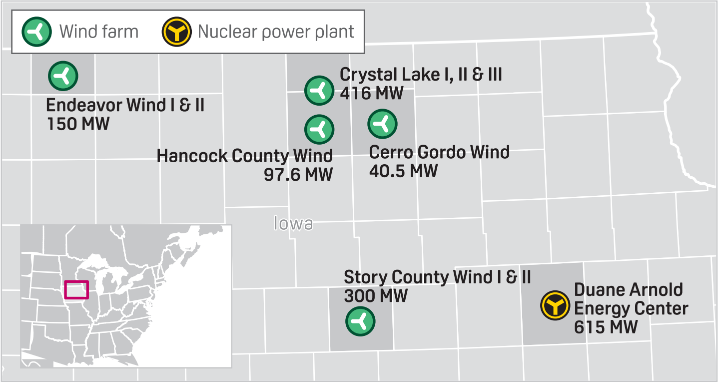
The NextEra Energy unregulated power subsidiary said July 27 that it plans to retire Iowa's only nuclear plant and announced that Alliant Energy, the plant's main purchaser of power, had agreed to shorten by five years a power purchase agreement in exchange for a $110 million buyout payment to be made in September 2020. The 20-year PPA with Alliant's Interstate Power and Light subsidiary was originally slated to continue through 2025.

Iowa regulators would have to approve the retirement of the plant and the change in the PPA, which is between NextEra Energy Resources and Alliant subsidiary Interstate Power and Light.

Manan Ahuja, senior director of North American power at S&P Global Platts Analytics, said July 30 "there is a precedent" for a state agency disallowing a nuclear plant retirement. The Michigan Public Service Commission, in effect delayed the retirement of the 845-MW Palisades nuclear power plant by limiting the recovery of PPA exit costs to $136.6 million, compared with the $172 million sought by CMS Energy, the buyer of the power, and Entergy, the owner of Palisades.

After previously announcing plans to shut down the plant in 2018, Entergy decided to keep Palisades open until 2022.

NEXTERA ENERGY RESOURCES' IOWA ASSETS



Source: S&P Global Platts

"In comparison, Duane Arnold is a smaller unit, and the cost of PPA termination is lower at $110 million," Ahuja said in an email. "Also, Iowa's resource adequacy is much healthier than Michigan. Iowa has about 0.5 to 1 GW of surplus installed capacity (over its planning reserve margin), so it should be able to absorb the loss of this capacity."

Wind, solar to be deployed

To replace at least part of the Duane Arnold unit's capacity, NextEra Energy Resources pledged to invest about $650 million in existing and new renewables generation, including $250 million to repower four existing wind farms in Iowa with about 340 MW of combined capacity.

NextEra Energy Resources is also "evaluating the redevelopment opportunities" at the Duane Arnold site, including perhaps a utility-scale solar power and storage facility, it said.

"As long as the wind blows in Iowa, and natural gas is cheap, standalone nukes are a dying breed," said Eric Smith, Tulane Energy Institute associate director, in an email July 30.

"I would think the only hope for a bailout would be some sort of state subsidy similar to others being considered in [New York] and elsewhere," Smith said. "Without such capacity payments, the plant simply is not viable. Even with capacity payments, it is questionable whether a nuke can ramp up quickly enough to make its standby power viable."

Asked how the Duane Arnold unit's retirement might affect Midcontinent Independent System Operator power prices, Ahuja said, "There may be some upside to prices due to the retirement, but bear in mind that [Iowa] already has relatively low wholesale power prices … as compared to other zones in MISO."

— Mark Watson, Houston

Kepco's APR1400 design receives NRC advisory committee approval

Korea Electric Power Corp.'s APR1400 reactor can be built without undue risk to the public, NRC's Advisory Committee on Reactor Safeguards said in a letter-report July 26.

The ACRS advises commissioners on technical issues and conducts reviews independent of NRC staff of licensing and regulatory actions.

However, the ACRS noted that the seismic probabilistic risk assessment accompanying the APR1400 application did not quantify seismic risks, saying that a more complete PRA for seismic issues would have to be completed before an APR1400 could load fuel.

Such seismic margin issues are often left for resolution on a site-specific basis in applications for a combined construction permit-operating license, NRC spokesman David McIntyre said in an email August 1.

NRC suggested in January that Korea Hydro & Nuclear Power remove an analysis of seismic margins from the design certification review because of concerns about the quality and completeness of company submittals in order to meet the 42-month published schedule for the design certification review.

This would still allow NRC to make the conclusion that the design provided reasonable assurance of adequate protection of the public as required in regulations, the agency said in a February 2 letter to KHNP.

However, KHNP officials declined to remove the seismic margin analysis, NRC said.

NRC expects to complete its final safety evaluation report of the design certification in September, according to a schedule on the agency website. Design certifications are handled as NRC rulemakings and the final rule is scheduled to be published in February, NRC said.

In the February 2018 letter and in a May licensing summary, NRC said there could be a delay to the published schedule depending on resolution of seismic issues.

However, McIntyre said staff still believes the schedule for September completion of the safety evaluation and a final rule next year can be met.

The APR1400 is a design owned by Kepco and its subsidiary KHNP. The design "evolved from" the Combustion Engineering System 80+ design that NRC certified in 1997, the ACRS said. Westinghouse eventually purchased Combustion Engineering and continues to provide services to CE-designed units.

The application for design certification was submitted in December 2014. The environmental review of the application was completed in 2015.

The agency has billed Kepco $57.3 million in fees in connection with the review, NRC said in a licensing update made public July 26.

There are no projects to build APR1400s in the US. However, KHNP officials have said NRC certification would be beneficial for sales of the reactor in other countries.

Four APR1400 units are being built at Barakah in the United Arab Emirates.

The ACRS said the APR1400 design "is mature and robust." While the main components remain the same as in the System 80+, upgrades were made to employ higher-strength materials and corrosion-resistant tubing to improve reliability, ACRS said.

The design adopts microprocessor-based digital instrumentation and controls, although a hardware-based timer produces a trip or alarm should key computer components fail, ACRS said. One-direction "data diodes" prevent access of external equipment to in-plant systems, boosting plant protection, ACRS said.

— William Freebairn, Washington

Orano reports first-half loss as front-end profits, investment returns drop

French fuel cycle company Orano said first-half profits fell as earnings from enrichment and conversion declined and investment returns dropped.

Orano reported a loss of Eur205 million ($239.6 million) for the first six months of the year, compared with a loss of Eur154 million for the same period in 2017. The loss came even as the company had several one-time charges in the first half of 2017 that did not recur.

Revenue for the first six months of the year was Eur1.71 billion, down from Eur1.79 billion in the same period of 2017, a decline of 4.5%, Orano said in a statement July 27.

Operating income, a measure of profits before interest, taxes and other costs, rose by Eur184 million over the first half of 2017, Orano said.

However, the operating income did not translate to profits because of poor returns on its investments, including Eur7.3 billion in assets held to ensure Orano has the ability to decommission its nuclear facilities.

Orano recorded a loss from financial instruments of Eur342 million for the first six months of the year, compared with a loss of Eur121 million in the same period of 2017, it said. The investment return on its assets was Eur23 million in the year through June, while the returns during the same period last year were Eur218 million. Orano attributed the difference to poor performance of financial markets this year as well as accounting changes that took effect January 1 requiring it to reflect the value of assets in its profit and loss statements.

Revenue in the company's mining division was Eur555 million, down 11.5% compared with theEur627 million recorded in the year-earlier period, Orano said. It attributed the decline to a drop in volume of uranium sold. While front-end revenue declined 12.7% because of a poor market for enrichment services and the end of conversion operations at its Comurhex I facility last year, back-end revenue increased 4.8% as Orano booked additional decommissioning contracts, it said.

Comurhex II, built to replace the older facility, is expected to produce UF6 later this year, Orano said. Orano has said it prepared for the transition between the two facilities by stockpiling UF6 for the period when it would have no operating conversion facility.

Orano said it booked Eur1 billion in new orders, particularly in Asia, which the company said represents an increasingly important part of its business.

The results in the first half of 2017 were affected by several one-time charges, including a Eur80 million contingency for end-of-life liabilities at front-end facilities and costs related to layoff of workers during the company's restructuring, it said. Orano also booked a Eur118 million charge related to a reduction of the value of its Comurhex II conversion facility in the first half of 2017 and another charge related to a loss of value of its Imouraren uranium mine in Niger.

— William Freebairn, Washington

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Hanul-2, currently shut for maintenance, restart before the second and third week of August when electricity demand peaks," the company said in a statement July 22.

The 1,047-MW Hanbit-3 has been shut for maintenance since May 11. The 1,012-MW Hanul-2 underwent maintenance from November 24 to May 10, but shut again July 12 because of problems with a valve, restarting July 28, KHNP said.

KHNP will also delay outages at Hanbit-1 and Hanul-1, it said. Those outages were scheduled to start in the second half of August, as summer demand is declining, KHNP said. Work at Hanbit-1 was originally scheduled for August 18 to November 7 and the outage at Hanul-1 was slated for August 29 to November 21.

KHNP has not released a revised schedule.

"As Hanul-4 with 1,000 MW which underwent maintenance since May 18 restarted on July 21, the five reactors will supply an additional

5 GW of electricity during peak time," KHNP said in its statement.

But the decision to operate more reactors this summer has been seen by some in the opposition party as a retreat from Moon's nuclear phaseout plan.

The main opposition party and many local media outlets said the Moon government has no choice but to resort to nuclear plants as weather extremes become more frequent, calling for Moon to scrap the nuclear phaseout.

The JoongAng Daily in an editorial July 24 criticized Moon's energy policy as "myopic."

"The government is hurriedly going back to nuclear reactors after energy concerns arose out of the blue," the newspaper said.

The Korea Herald also said in its editorial July 23 that the Moon government, which has vowed to stop using nuclear energy, is "paradoxically" increasing the use of nuclear power plants this summer. "This shows how absurd it is to push for the disuse of nuclear energy without alternatives," it said.

No change to phaseout policy

But the government ruled out any change in the nuclear phaseout policy.

"The government has been seeking to produce electricity as much as possible during the peak times by putting more nuclear reactors and thermal power plants online, and therefore this has nothing to do with the energy transition policy," MOTIE's Jeong said.

Choi Woo-Seok, chief of MOTIE's power industry department, also said that the country has enough capacity to deal with peak summer demand, ruling out any change in the phaseout policy.

"There won't be serious problems in the supply management during the peak period," he said in an interview July 27.

Under Moon's phaseout policy, the country's oldest reactor, Kori-1, was shut permanently in June 2017 in a move described by Moon as the "start of a journey to becoming a nuclear-free nation." A year later, KHNP approved permanent closure of Wolsong-1.

Moon has vowed to permanently shut other reactors without extending their initial 30-year operating lifespan while scrapping plans to build new reactors. Moon has said his anti-nuclear policy will pave the way for achieving a nuclear-free South Korea by 2079.

— Charles Lee, Seoul

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needed by many existing operations to produce profitably."

The daily U3O8 spot price rose from $24.75/lb July 25, prior to Cameco's McArthur River announcement, to $25.75/lb the next day, according to price reporting company TradeTech. TradeTech reported the price at $25.85/lb July 31.

Garrow said, "The utilities are saying 'spot prices are strengthening a bit, so we're going to step back [from buying] as this increase may be an overreaction'" to the Cameco announcement.

However, Garrow said, utilities fail to recognize "they're no longer the driving force in the spot market," noting that two other groups are exerting greater influence.

Financial entities such as Yellow Cake PLC have started buying uranium for investment purposes, he said.

> Uranium market participants debate whether mine shut-down will raise price'Utilities are saying they can't buy above $30 a pound and producers say they can't sell at below $40'
> — Dustin Garrow, nuclear fuel consultant

Yellow Cake said after an early July initial public offering that it has bought 8.1 million lb U3O8 from Kazatomprom. Yellow Cake said in a July 5 statement that it intends to "hold long-term physical uranium."

Garrow noted that Australia's Tribeca Investment Partners is seeking to launch a fund to buy uranium. The new fund is looking to raise $100 million for that purpose, The Australian Financial Review reported June 12.

Also, Garrow said, when Cameco begins to buy 11 million lb-15 million lb between now and the end of 2019 — plans announced by company executives during a July 26 second-quarter conference call — the company "principally will look at the spot market" to acquire this material.

"The probability for [U3O8 spot] price strengthening is significantly higher than price stability or decline," he said.

The "Section 232 petition is causing utilities to be hesitant to do any contracting … and they won't commit to" make any long-term uranium purchases, Garrow said. Consequently, he said, when utilities need to re-enter the market, they will compete to conclude long-term uranium supply contracts, and the prices they pay likely will be significantly higher than current prices.

Market uncertainties grow

A petition that US uranium producers Energy Fuels and Ur-Energy jointly filed with the US Department of Commerce January 19 under Section 232 of the Trade Expansion Act of 1962 asked the department to investigate the impacts of uranium imports to the US, claiming they pose a threat to national security. Domestically produced uranium currently provides less than 5% of US utilities' need for that material, they said. The petition also asked Commerce to recommend that President Donald Trump require US nuclear utilities to purchase 25% of their uranium domestically.

Secretary of Commerce Wilbur Ross announced July 18 that the department is investigating whether uranium imports "threaten to impair" US national security.

Under the 1962 law, Commerce has 270 days to conduct the investigation and submit a report to Trump, along with proposed remedies. Trump then would have up to 90 days to act on the recommendations and to make any adjustments, if needed, to the imports.

The result of the trade action filing, and questions about the timing of Cameco's purchases, "are uncertainties in the market that we haven't seen in 40 years," Garrow said. "Utilities are saying they can't buy [U3O8] above $30 a pound and producers say they can't sell at below $40" a pound.

Garrow said available uranium production is under further pressure given the shutdown in 2017 of Paladin's Langer Heinrich mine in Namibia, which is being kept on care and maintenance following the company's reorganization early this year. This conventional mine, he said, had reliably sold up to 5 million lb U3O8 annually on the spot market.

In 2017, US uranium producers produced abut 1.1 million lb, according to the US Energy Information Administration. EIA estimated in its May 22 annual domestic uranium production report that the annual production capacity of ISR and conventional uranium mines, most of which are on standby or in various stages of permitting, totals 26.95 million lb. Numerous US uranium producers interviewed this year said they would need to feel confident that the U3O8 spot price would be sustained between $40 and $60 a lb before they would ramp up production at existing facilities, or consider developing greenfield, fully permitted ones.

Fuel buyer says concerns 'overblown'

A fuel buyer said in a July 30 interview such warnings "probably are overblown." Cameco's announced purchasing "is a short-term thing. It will be buying because it's not producing" from McArthur River, "and this isn't true demand," said the buyer, who spoke on condition of anonymity because he is not authorized to speak for his company.

Noting that NextEra Energy Resources' Duane Arnold nuclear plant will shut in 2020, and Exelon's Oyster Creek will do so in September 2018, the fuel buyer said that "demand [for U3O8] is leaving the marketplace, not increasing."

The fuel buyer said those who argue that utilities should buy U3O8 now, because prices are sure to rise substantially in the near future, "reminds me of people saying you should buy a beach condo now because prices are only going up and up."

The fuel buyer acknowledged that utilities will have to enter the market in future years to conclude longer-term uranium supply contracts, but emphasized, "It's not as if we're all going to be in the market at the same time scrambling to buy uranium."

"The [U3O8 spot] price might move up a bit, but the feeling is that it will fall back and we won't get to anywhere near $50 [a lb] by the end of next year," the buyer said.

— *Jim Ostroff, Washington*

