Cash categories include:

- Labor: represents all labor costs, including overtime and fringe benefits associated with plant operations and outages.
- Materials: includes materials and tools.
- Outside services: primarily contractors and maintenance support.
- Real Estate Tax.
- Support Services and Fully Allocated Overhead: includes administrative and general expenses, costs associated with insurance, costs incurred outside of the site that directly support site activities, and corporate overhead costs.
- Spent fuel: Upon enactment of the Nuclear Waste Policy Act of 1982 (NWPA), the Department of Energy ("DOE") began collecting a charge from nuclear generators for the costs of fulfilling its legal obligation to dispose of the nuclear fuel used to generate power. Most recently, this fee was assessed on a $/MWh basis at a rate of $0.955/MWh. However, when development of Yucca Mountain was discontinued, this fee was suspended by court order in May 2014, at which point PSEG ceased accruing for that expense in its financial statements. Until a disposal solution is identified and a new fee structure is placed in effect, PSEG will not accrue for that expense. But we recognize that the NWPA is still in effect and DOE still has a legal obligation to dispose of nuclear fuel and will need to pay for the costs of whatever that ultimate solution is through a fee on nuclear generators. Accordingly, to approximate this cost, PSEG has included the fee on generation at its suspended rate of $0.955/MWh in its financial projections. We also note that this cost was recognized and included in the NY ZEC process as a reasonable risk factor that nuclear generation owners need to ensure they can cover in order to remain in operation economically.
- Cost of working capital (forecast years): Nuclear plants require a net investment in working capital. The most significant components of working capital include materials and supplies inventory to ensure reliable operation, long positions in nuclear fuel, and revenue receivables primarily from the sale of electricity and capacity, offset by accrued expenses and payables necessary to operate the units. In addition, there is a cost related to collateral / margin payments to counterparties for hedging. To determine the cost of working capital, a value of net working capital is determined based on the most recent quarterly financial statements (6/30/20) and that amount is multiplied by Power's average interest rate (4.60%) to arrive at the cost of net working capital by unit. That cost is then divided by the forecasted generation for 2021 to determine a $/MWh rate to be used in future periods. This rate is then escalated at 2.5% to determine the cost of working capital for future years. See below for the $/MWh calculation used to derive the cost of working capital.

[redacted]

- Other: includes long-term fuel storage costs, regulatory fees, membership fees, facilities and rental costs, office expenses, business travel, etc.
- Fuel capital expenditures: represents the fuel capital expenditures associated with refueling outages.
- Non-fuel capital expenditures: spending on long-lived plant equipment required to maintain safe and reliable operations.
- Cost of Operational Risks: The cost of operational risks that would be avoided by ceasing operations. PSEG has submitted its best estimate of the future unit costs as part of this application. However, actual realized operating costs may turn out to be higher than projected costs for a variety of reasons despite best practices employed by the operator. In order to reflect the uncertainty in its cost forecast, PSEG includes a cost of operational risk in its financial evaluation equal to 10% of total costs, which is consistent with operating cost estimation rules adopted in the FERC-approved PJM tariff.

  'Operational risks' are defined in the statute as "the risk that operating costs will be higher than anticipated because of new regulatory mandates or equipment failures and the risk that per megawatt-hour costs will be higher than anticipated because of a lower than expected capacity factor."[1] This risk is particularly pronounced for nuclear plants, which are subject to stringent safety and security focused regulatory oversight by the U.S. Nuclear Regulatory Commission (NRC), and can face significant unforeseen regulatory requirements at any time. The NRC is a federal agency established to regulate nuclear activities to ensure protection of public health and safety, security, and protection of the environment. The unit may be required to increase capital expenditures and/or operating costs at the nuclear facilities when there is a change in the Atomic Energy Act, applicable regulations, or the environmental rules and regulations applicable to nuclear facilities. Additionally, if a major component unexpectedly fails, the facility will bear the unanticipated and significant cost of replacing the component. Unexpected equipment failure and nuclear regulatory changes have increased nuclear costs at New Jersey nuclear plants by hundreds of millions of dollars in the last decade.

The upgrades required for all U.S. nuclear plants in response to the nuclear event at the Fukushima Dai-Ichi plant in Japan in 2011 are a recent example of such operating cost risk. The NRC issued the following orders: 1) Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events 2) Order to Modify Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation under Sever Accident Conditions 3) Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation. Additionally, a request for information under 10 CFR § 50.54(f) was issued which required performance of activities for seismic and flooding reevaluations and walk downs, and revaluation of emergency communications systems and staffing levels. These upgrades required expenditures of approximately $105 million at Salem and Hope Creek.

Since September 11, 2001, NRC has issued many security related Orders to Nuclear Plants. These Orders included measures to protect against an insider terrorist attack; waterborne, airborne, and land-based assaults; as well as threats from a vehicle bomb. The specific security measures generally include increased patrols, augmented security forces and capabilities, additional security posts, installation of additional physical barriers, vehicle checks at greater stand-off distances, enhanced coordination with law enforcement and military authorities, and more restrictive site access controls. The post 9/11 security requirements cost approximately $140 million for Salem and Hope Creek.

NRC research on High Energy Arc Faults is presently underway. Addressing this type of fault has the potential to result in significant regulatory impact. The NRC has added this concern to their "Generic Safety Issue (GSI)" process. Prior GSI issues included #191 which entailed containment sump viability and resulted in expenditures of approximately $26 million for the Salem Units. Similarly, the on-going U.S. Department of Commerce section 232 uranium investigation is an example of a prospective operating risk that could result in actual operating costs in excess of those projected.

An example of a costly equipment failure is the unexpected steam generator replacement in 2008 required expenditures of approximately ~$266 million at Salem Unit 1. In addition,

[1] L. 2018, c. 16, codified at N.J.S.A. 48:3-87.3 to 87.7.

the cumulative impact of even relatively modest capital projects required to address unforeseeable equipment failure issues can be quite significant.

Unexpected outages for repairs not only increase the total unit costs, but can also dramatically increase the per MWh cost. Nuclear facility costs are largely fixed—that is, they remain largely the same even if plant output declines. So, reduced output alone can translate to a significant increase in the cost per MWh of output. Moreover, while nuclear facilities generally are highly reliable, when an unplanned nuclear outage does occur, it can be prolonged.

The cost increase on a per MWH basis related to a reduced capacity factor is proportional to the reduction in output. Specifically, actual costs equal projected costs multiplied by 1 / (1 – reduction in capacity factor). For example, if a unit's projected costs are $500 million and projected output is 10 million MWh, this translates to a cost of $50/MWh ($500 million / 10 million MWh). If instead, that facility's output is reduced by 10 percent to 9 million MWh, then costs become $55.55/MWh ($500 million / 9 million). So, given a 10 percent reduction in output, actual costs per MWh turn out to be 11.1 percent higher than projected.

To account for the cost of these risks, PSEG uses a cost of operational risks of 10 percent of projected operating costs. Using a 10-percent adder to account for the risk of higher-than-expected costs is consistent with the approach taken by PJM Interconnection L.L.C. ("PJM"), as approved by FERC, to determine a facility's avoidable costs, for both energy and capacity bids. In the PJM Open Access Transmission Tariff (OATT) section relative to Avoidable Cost Rate for capacity bids, PJM specifies an operating cost gross-up adjustment factor of 10% to "provide for a margin of error for understatement of costs."[2] In the PJM OATT section relative to energy offer price caps, PJM allows a 10 percent adder.[3] FERC has not only approved these adjustment factors but also specifically commented, "The 10 percent adder is allowed for determining these ex ante bids in order to account for uncertainty in the values of the costs utilized in computing those cost-based offers before all costs are known."[4] Additionally, in the New York ZEC program, the estimated operational risks provided by the nuclear plant owner was also 10 percent of total costs. The pricing structure developed by the New York Public Service Commission accounted for this risk.[5]

- Cost of Market Risks: The estimated costs of market risks shown in response to this question are based on the following estimates: a) for the period from January 2021 through May 2022, the estimated cost of market risk submitted in the application for the first ZEC eligibility period, and b) for the period from June 2022 through December 2025, the estimated cost of market risks submitted as part of this application for the

[2] PJM Open Access Transmission Tariff, Attachment DD, Section 6.8(a).
[3] PJM Open Access Transmission Tariff, Attachment K, Appendix, Section 6.4.
[4] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,289, P 30 (Dec. 11, 2015)
[5] *See* CENG Comments in response to the Notice Soliciting Comments and Providing for Technical Conference and Public Statement Hearings issued by the State of New York Public Service Commission on January 25, 2016 in Case 15-E-0302.

second ZEC eligibility period[6]. The methodology and calculations for the estimated costs of market risks are detailed in response to question ZECJ-FIN-18.

- Please note that, for past years, the costs of operational risks are included in the realized results. The costs of market risks materialized in the revenue results of PSEG's portfolio of NJ Nuclear generating units and hedges prorated to these units. By definition, risk represents uncertainty about the future, relative to an expectation of the future at a particular point in time, and is a forward-looking concept. Realized operating costs, generation outages, rates and market prices, which are drivers to the costs of operational risk and of market risk, are reflected in the actual revenues and cost line items.

- Uranium fuel pricing $/lb: Uranium U308 component only. Historical costs are actuals. Forward prices are derived from expected costs of existing contracts and expected forward prices from industry sources for requirement not currently under contract.

[6] The cost of market risks for individual years would differ from the estimates given above based on three-year ZEC eligibility periods. The price risk component of the overall cost of market risk is generally lower for years that are closer in the future than for years that are further out, given that a) the period of time over which future energy market volatility takes effect is shorter, b) the years further out entail more capacity market uncertainty, and c) the energy hedging levels are higher for the years that are closer.