AES

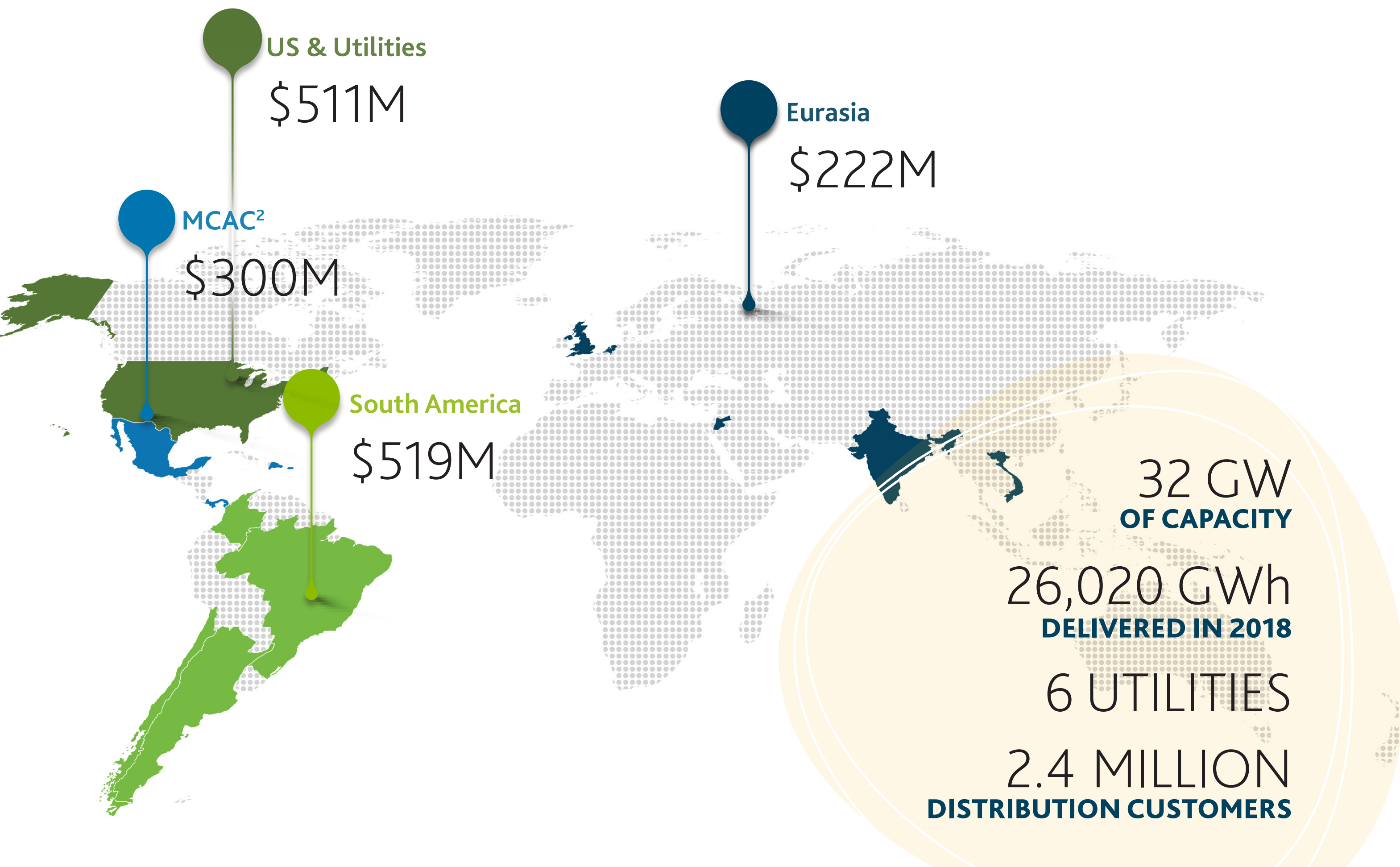
we are the energy

2018 | ANNUAL REPORT

About AES

The AES Corporation – We are a global power company with generation and distribution businesses. Through our diverse portfolio of thermal and renewable fuel sources, we provide affordable and sustainable energy to 15 countries. Our workforce of 9,000 people is committed to operational excellence and meeting the world's changing power needs.

ADJUSTED PTC[1] BY SBU



[1] A non-GAAP financial measure. See Financial Notes on page 8 for definition and reconciliation to the nearest GAAP number.
[2] Mexico, Cnetral America and the Caribbean.

AES VALUES

SAFETY	INTEGRITY	AGILITY	FUN	EXCELLENCE

Strategic Overview

DELIVERING ON OUR COMMITMENTS

2018 — Adjusted EPS[1] of **$1.24** vs. Guidance of **$1.15-$1.25**

Parent Free Cash[3] Flow of **$689M** vs. expectation of **$600-$675M** — **2018**

Achieved a key investment grade metric in 2018 and expect to attain ratings in 2020

PARENT LEVERAGE RATIOS:

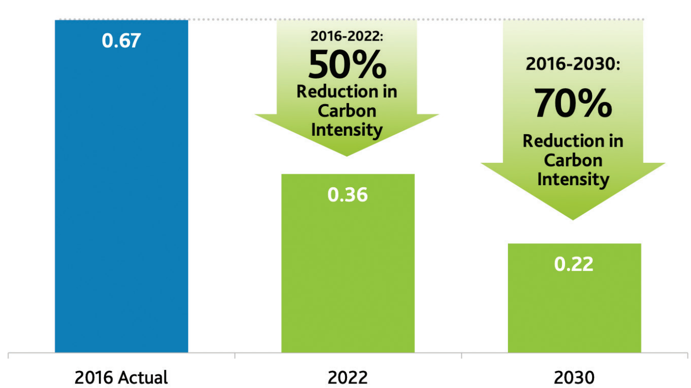
3.95x as of Dec. 31, 2018 vs. **4.9x** as of Sep. 30, 2016

[3] Parent Free Cash Flow (a non-GAAP financial measure) should not be construed as an alternate to Net Cash Provided by Operating Activities which is determined in accordance with GAAP. Parent Free Cash Flow is equal to Subsidiary Distribution less cash used for interest costs, general and administrative activities, and tax payments by the parent company. Parent Free Cash Flow is used for dividends, share repurchases, growth investments, recourse debt repayments, and other uses by the parent company.

FLUENCE
A Siemens and AES Company

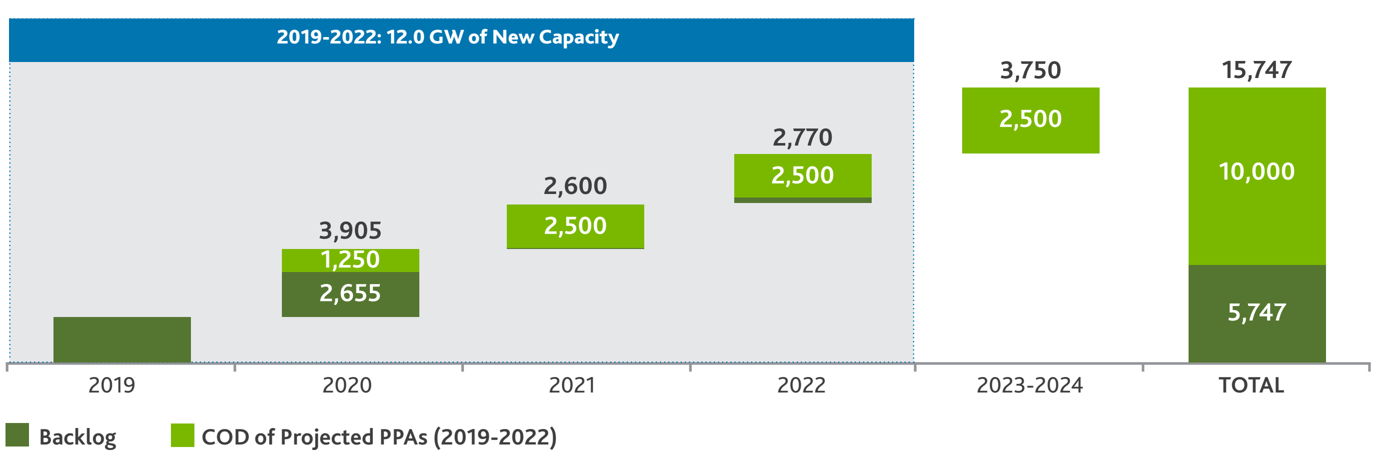
NAVIGANT

REDUCING CARBON INTENSITY BY 50% BY 2022 AND 70% BY 2030



STRONG BACKLOG DRIVES FUTURE GROWTH

Backlog = Under Construction + Signed PPAs Not Yet Under Construction



Chairman and CEO Letter to AES Shareholders

2018 was a very good year for AES, demonstrated by our strong financial results and excellent progress toward achieving our strategic goals. 2018 was also a significant year in our overall transformation, which positions us well to continue to accomplish our mission to improve lives, while at the same time deliver attractive returns to our shareholders.

Delivering on Our Commitments

In 2018, we delivered on all of our commitments, including achieving our financial guidance, hitting key milestones on our strategy and positioning AES for long-term, sustainable growth. Some key accomplishments this year included:

- Adjusted EPS of $1.24, compared to guidance of $1.15 to $1.25;
- Parent Free Cash Flow of $689 million, compared to our expectation of $600 to $675 million;
- Total Shareholder Return (TSR) of 39%, outperforming the S&P 500 and S&P Utilities Indexes;
- Signed long-term Power Purchase Agreements (PPA) for approximately 2 GW of renewable capacity, increasing our backlog to almost 6 GW;
- Completed construction of 1.3 GW across our portfolio;
- Paid down $1 billion in Parent debt, enabling us to achieve a key investment grade financial metric of 3.95x Parent leverage one year early; and
- Expanded our world-leading battery-based energy storage business, including the launch of our joint venture with Siemens, Fluence, which was awarded 286 MW of new projects.

Strong Backlog Drives Future Growth

Our strong backlog of 5,787 MW includes both our conventional and renewable capacity under construction, as well as our renewables under signed PPAs that are not yet under construction. During the year, we completed construction of an additional 1,278 MW, including several transformative projects.

At our utility, Indianapolis Power and Light (IPL) in Indiana, we completed the 671 MW Eagle Valley combined cycle gas plant. The completion of Eagle Valley also represents the conclusion of a significant investment program at IPL, wherein we have replaced nearly half of IPL's coal-fired generation with cleaner and more efficient natural gas.

In Panama, we completed the 381 MW AES Colón combined cycle gas plant and regasification terminal, and made the first shipment of LNG in Central America's history. The LNG storage tank is expected to come on-line in the middle of 2019, with approximately 60% of the terminal's capacity still available to be contracted. We expect that the entry of low-cost U.S. LNG will transform the Central American energy sector, much as it has in the Dominican Republic.

We believe the integration of renewables and energy storage is the key to accelerating a cleaner energy future. In Hawaii, we are delivering two solar plus storage facilities for a total of 34 MW of solar capacity and 170 MWh of five-hour energy storage on the island of Kaua'i. The first of these pioneering projects, Lāwa'i was completed in December 2018 and will satisfy energy demand during peak hours in the evening, as well as the rest of the day. The second, Kekaha, is under construction and expected to be on-line later in 2019.

We have 4,440 MW of capacity under construction and expected to come on-line through 2021. Our primary projects under construction include: the 1,320 MW OPGC 2 project in India, the 1,384 MW Southland repowering in Southern California and the 531 MW Alto Maipo project in Chile.

In 2018 we signed 1,946 MW of renewables under long-term PPAs and expect to sign an additional 2,000 to 3,000 MW per year through 2022. This capacity should be split equally between the U.S. and internationally, and similarly between solar and wind. In the U.S., the majority of our expected growth will come from our sPower and AES Distributed Energy (AES DE) businesses. We are also focusing on our "Green Blend and Extend" strategy, where we are enhancing some of our current contracts by blending and extending existing PPAs, by adding renewable energy. We see potential opportunities to execute this strategy across many of our markets, including Chile and Mexico. In fact, in 2018 we signed our first two "Green Blend and Extend" contracts, for 576 MW in Chile and Mexico. In the near-term, we see an addressable

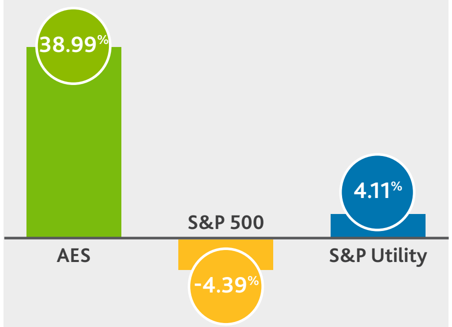


Figure 1. **2018 Total Shareholder Return**

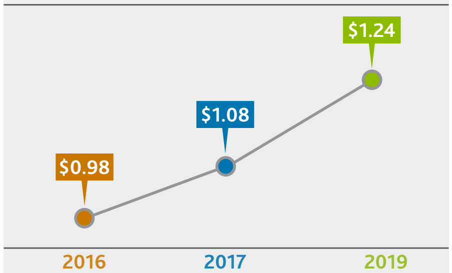


Figure 2. **2016-2018 Adjusted EPS[1] by year**

[1] A non-GAAP financial measure. See Financial Notes on page 8 for definition and reconciliation to the nearest GAAP number

universe of 7 GW across our portfolio, which could substantially increase as our markets capitalize on the economic benefit of renewables.

Our total backlog of 5,787 MW will be a key contributor for our expected earnings and cash flow growth of 7% to 9% per year through 2022.

MEMBER OF
Dow Jones Sustainability Indices
In Collaboration with RobecoSAM

Reducing Carbon Intensity by 50% by 2022 and 70% by 2030

We recently announced that based on our renewable growth plans, we expect to reduce our carbon intensity (tons of CO2/MWh of generation) by 70% from 2016 to 2030. This is an improvement from our prior goal of 50% over the same period. Furthermore, we also announced a near-term target of reducing our carbon intensity by 50% from 2016 to 2022, compared to our prior goal of 25% over the same period.

In November 2018, we published the AES Climate Scenario Report, which includes an impact analysis of a 2° Celsius scenario on our strategy and business, fulfilling our April 2018 commitment to adopt the recommendations of the Task Force on Climate-related Financial Disclosures (TCFD). AES was the first publicly-traded owner of utilities and power companies based in the U.S. to disclose its portfolio's resilience consistent with the TCFD recommendations and third-party scenarios. The report shows that AES' portfolio is resilient against the assessed climate risks and demonstrates the significant upside for AES in a lower carbon future.

In 2018, AES was named to the Dow Jones Sustainability Index (DJSI) for North America for the fifth year in a row by RobecoSAM. We were also named by Ethisphere as one of the World's Most Ethical Companies for the fifth year in a row. These recognitions validate the degree to which every member of the AES team lives by our values.

AES Values

- **SAFETY:** We will always put safety first–for our people, contractors and communities.
- **INTEGRITY:** We are honest, trustworthy and dependable. Integrity is at the core of all we do–how we conduct ourselves and interact with all of our stakeholders.
- **AGILITY:** We move with vision, speed and flexibility to adapt to our dynamic and rapidly changing world.
- **FUN:** We work because work can be fun, fulfilling and exciting.
- **EXCELLENCE:** We strive to be the best in all that we do and to perform at world-class levels.

Investing in Innovative Technologies for Additional Upside

We continue to invest in innovative technologies, such as battery-based energy storage, drone applications and digital customer interfaces. These initiatives have already allowed us to reduce O&M costs, improve customer experiences and deliver new solutions to the market.

In January 2018, we formed Fluence, our energy storage joint venture with Siemens. During the year, Fluence delivered or was awarded 80 projects in 17 countries, with a total capacity of 766 MW. Notably, Fluence was also named the #1 utility energy storage integrator by Navigant.

We are also implementing a corporate-wide digital transformation, including becoming a strategic investor in Simple Energy.

Simple Energy provides a digital platform that allows our IPL and DPL utilities to accelerate energy efficiency and demand response programs, while improving customer experience.

Although not in our guidance, we expect our new digital initiatives to materially benefit both our top and bottom lines.

Jay Morse and Andrés Gluski

Achieved a Key Investment Grade Financial Metric and Expect to Attain Ratings in 2020

In the third quarter of 2016, we established a goal of reaching investment grade. At that time, we had $5 billion in Parent debt and a Parent Debt/EBITDA coverage ratio of 4.9x. Since then, we have reduced debt by $1.3 billion and ended this year with a Parent leverage ratio of 3.95x, achieving our goal a year ahead of our plan. We are now very well-positioned to attain investment grade ratings in 2020.

	Fitch	Moody's	S&P
2016	BB-	Ba3	BB
2018	BB+	Ba1	BB+

Figure 3. **Achieved a key Investment Grade Metric and Expect to Attain Ratings in 2020**

Offering Double-Digit Total Return Annually Through 2022

We continued to improve the returns from our existing portfolio and position AES for long-term, sustainable growth. We will achieve this objective as we continue to optimize our costs, strengthen our Balance Sheet, reduce our carbon intensity and deploy new technologies in our existing markets. Combining our current dividend yield of 3.2%, and our 7% to 9% average annual growth in Adjusted EPS and Parent Free Cash Flow, will yield a double-digit total return annually through 2022.

Thank you for your continued support.

Jay Morse
Chairman and Lead Independent Director
March 1, 2019

Andrés Gluski
President and Chief Executive Officer
March 1, 2019

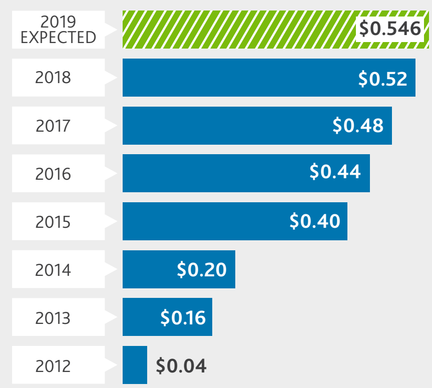


Figure 4. **2012-2019 Shareholder Dividend by year**

Financial Measures: Non-GAAP Financial Measures Reconciliation (Unaudited)

	Year Ended December 31		
($ in millions, except per share amounts)	2018	2017	2016
Reconciliation of Adjusted Earnings Per Share (1)			
Diluted Earnings (Loss) Per Share From Continuing Operations	**$1.48**	**$(0.77)**	**$(0.04)**
Effect of anti-dilutive securities	—	0.01	—
Non-GAAP diluted earnings (loss) per share from continuing operations	1.48	(0.76)	(0.04)
Unrealized derivative and equity securities losses (gains)	0.05	—	(0.01)
Unrealized foreign currency losses (gains)	0.09(2)	(0.10)	0.03
Disposition/acquisition losses (gains)	(1.41)(3)	0.19(4)	0.01
Impairment expense	0.46(5)	0.82(6)	1.41(7)
Loss on extinguishment of debt	0.27(8)	0.09(9)	0.05(10)
Restructuring costs	—	0.05	—
U.S. Tax Law Reform Impact	0.18(11)	1.08(12)	—
Less: Net income tax expense (benefit)	0.12(13)	(0.29)(14)	(0.51)(15)
Adjusted Earnings Per Share (1)	**$1.24**	**$1.08**	**$ 0.94**
Reconciliation of Adjusted Pre-Tax Contribution (16)			
Income (Loss) From Continuing Operations Attributable to AES	**$985**	**$(507)**	**$(20)**
Add: Income tax expense (benefit) attributable to AES	563	828	(111)
Pre-tax contribution	1,548	321	(131)
Unrealized derivative and equity securities losses (gains)	33	(3)	(9)
Unrealized foreign currency losses (gains)	51	(59)	22
Disposition/acquisition losses (gains)	(934)	123	6
Impairment expense	307	542	933
Loss on extinguishment of debt	180	62	29
Restructuring costs	—	31	—
Adjusted Pre-Tax Contribution (16)	**$1,185**	**$1.017**	**$ 850**

1. We define Adjusted Earnings Per Share ("Adjusted EPS"), a non-GAAP measure, as diluted earnings per share from continuing operations excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, and the tax impact from the repatriation of sales proceeds; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation; and (g) tax benefit or expense related to the enactment effects of 2017 U.S. tax law reform and related regulations and any subsequent period adjustments related to enactment effects. The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. AES believes that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose of or acquire business interests, retire debt or implement restructuring initiatives, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.
2. Amount primarily relates to unrealized FX losses of $22 million, or $0.03 per share, associated with the devaluation of long-term receivables

denominated in Argentine pesos, and unrealized FX losses of $14 million, or $0.02 per share, on intercompany receivables denominated in Euros and British pounds at the Parent Company.

3. Amount primarily relates to gain on sale of Masinloc of $772 million, or $1.16 per share, gain on sale of CTNG of $86 million, or $0.13 per share, gain on sale of Electrica Santiago of $36 million, or $0.05 per share, gain on remeasurement of contingent consideration at AES Oahu of $32 million, or $0.05 per share, gain on sale related to the Company's contribution of AES Advancion energy storage to the Fluence joint venture of $23 million, or $0.03 per share and realized derivative gains associated with the sale of Eletropaulo of $21 million, or $0.03 per share; partially offset by loss on disposal of the Beckjord facility and additional shutdown costs related to Stuart and Killen at DPL of $21 million, or $0.03 per share.

4. Amount primarily relates to loss on sale of Kazakhstan CHPs of $49 million, or $0.07 per share, realized derivative losses associated with the sale of Sul of $38 million, or $0.06 per share, loss on sale of Kazakhstan HPPs of $33 million, or $0.05 per share, and costs associated with early plant closures at DPL of $24 million, or $0.04 per share; partially offset by gain on Masinloc contingent consideration of $23 million, or $0.03 per share and gain on sale of Miami Fort and Zimmer of $13 million, or $0.02 per share.

5. Amount primarily relates to asset impairments at Shady Point of $157 million, or $0.24 per share, and Nejapa of $37 million, or $0.06 per share, and other-than-temporary impairment of Guacolda of $96 million, or $0.14 per share.

6. Amount primarily relates to asset impairments at Kazakhstan CHPs of $94 million, or $0.14 per share, at Kazakhstan HPPs of $92 million, or $0.14 per share, at Laurel Mountain of $121 million, or $0.18 per share, at DPL of $175 million, or $0.27 per share and at Kilroot of $37 million, or $0.05 per share.

7. Amount primarily relates to asset impairments at DPL of $859 million, or $1.30 per share, at Buffalo Gap II of $159 million ($49 million, or $0.07 per share, net of NCI) and at Buffalo Gap I of $77 million ($23 million, or $0.03 per share, net of NCI).

8. Amount primarily relates to loss on early retirement of debt at the Parent Company of $171 million, or $0.26 per share.

9. Amount primarily relates to losses on early retirement of debt at the Parent Company of $92 million, or $0.14 per share, at AES Gener of $20 million, or $0.02 per share, and at IPALCO of $9 million or $0.01 per share; partially offset by a gain on early retirement of debt at AES Argentina of $65 million, or $0.10 per share.

10. Amount primarily relates to the loss on early retirement of debt at the Parent Company of $19 million, or $0.03 per share.

11. Amount relates to a SAB 118 charge to finalize the provisional estimate of one-time transition tax on foreign earnings of $194 million, or $0.29 per share, partially offset by a SAB 118 income tax benefit to finalize the provisional estimate of remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $77 million, or $0.11 per share.

12. Amount relates to a one-time transition tax on foreign earnings of $675 million, or $1.02 per share and the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $39 million, or $0.06 per share.

13. Amount primarily relates to the income tax expense under the GILTI provision associated with the gains on sales of business interests, primarily Masinloc, of $97 million, or $0.15 per share, and income tax expense associated with gains on sale of CTNG of $36 million, or $0.05 per share and Electrica Santiago of $13 million, or $0.02 per share; partially offset by income tax benefits associated with the loss on early retirement of debt at the Parent Company of $36 million, or $0.05 per share, and income tax benefits associated with the impairment at Shady Point of $33 million, or $0.05 per share.

14. Amount primarily relates to the income tax benefit associated with asset impairments of $148 million, or $0.22 per share.

15. Amount primarily relates to the income tax benefit associated with asset impairments of $332 million, or $0.50 per share.

16. We define Adjusted Pre-Tax Contribution ("Adjusted PTC"), a non-GAAP measure, as pre-tax income from continuing operations attributable to AES excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis adjusted for the same gains or losses excluded from consolidated entities. The GAAP measure most comparable to Adjusted PTC is income from continuing operations attributable to AES. AES believes that Adjusted PTC better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose of or acquire business interests, retire debt or implement restructuring initiatives, which affect results in a given period or periods. In addition, earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Given its large number of businesses and complexity, the Company concluded that Adjusted PTC is a more transparent measure that better assists investors in determining which businesses have the greatest impact on the Company's results. Adjusted PTC should not be construed as an alternative to income from continuing operations attributable to AES, which is determined in accordance with GAAP.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2018
-OR-

☐ **TRANSITION REPORT FILED PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

COMMISSION FILE NUMBER 1-12291

THE AES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**54 1163725**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
4300 Wilson Boulevard Arlington, Virginia	**22203**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (703) 522-1315
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☒ No ☐

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐ Non-accelerated filer ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates on June 29, 2018, the last business day of the Registrant's most recently completed second fiscal quarter (based on the adjusted closing sale price of $13.05 of the Registrant's Common Stock, as reported by the New York Stock Exchange on such date) was approximately $8.63 billion.

The number of shares outstanding of Registrant's Common Stock, par value $0.01 per share, on February 21, 2019 was 662,358,244.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Registrant's Proxy Statement for its 2019 annual meeting of stockholders are incorporated by reference in Parts II and III

THE AES CORPORATION FISCAL YEAR 2018 FORM 10-K
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GLOSSARY OF TERMS

The following terms and abbreviations appear in the text of this report and have the definitions indicated below:

Adjusted EPS	Adjusted Earnings Per Share, a non-GAAP measure
Adjusted PTC	Adjusted Pre-tax Contribution, a non-GAAP measure of operating performance
AES	The Parent Company and its subsidiaries and affiliates
AOCI	Accumulated Other Comprehensive Income
AOCL	Accumulated Other Comprehensive Loss
ASC	Accounting Standards Codification
ASEP	National Authority of Public Services
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BOT	Build, Operate and Transfer
BTA	Best Technology Available
CAA	United States Clean Air Act
CAMMESA	Wholesale Electric Market Administrator in Argentina
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals, which includes bottom ash, fly ash and air pollution control wastes generated at coal-fired generation plant sites.
CDPQ	La Caisse de dépôt et placement du Quebéc
CEN	Coordinador Electrico Nacional
CEO	Chief Executive Officer
CFE	Federal Electricity Commission
CHP	Combined Heat and Power
COFINS	Contribuição para o Financiamento da Seguridade Social
CO_2	Carbon Dioxide
COSO	Committee of Sponsoring Organizations of the Treadway Commission
CP	Capacity Performance
CPI	United States Consumer Price Index
CPP	Clean Power Plan
CRES	Competitive Retail Electric Service
CSAPR	Cross-State Air Pollution Rule
CTNG	Compañia Transmisora del Norte Grande
CWA	U.S. Clean Water Act
DG Comp	Directorate-General for Competition of the European Commission
DP&L	The Dayton Power & Light Company
DPL	DPL Inc.
DPLER	DPL Energy Resources, Inc.
DPP	Dominican Power Partners
EBITDA	Earnings before Interest, Taxes, Depreciation & Amortization
EPA	United States Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERCOT	Electric Reliability Council of Texas
ESP	Electric Security Plan
EU	European Union
EURIBOR	Euro Inter Bank Offered Rate
EUSGU	Electric Utility Steam Generating Unit
EVN	Electricity of Vietnam
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FONINVEMEM	Fund for the Investment Needed to Increase the Supply of Electricity in the Wholesale Market
FPA	Federal Power Act
FX	Foreign Exchange
GAAP	Generally Accepted Accounting Principles in the United States
GDPR	General Data Protection Regulation
GHG	Greenhouse Gas
GILTI	Global Intangible Low Taxed Income
GRIDCO	Grid Corporation of Odisha Ltd.
GWh	Gigawatt Hours
HLBV	Hypothetical Liquidation Book Value
IDEM	Indiana Department of Environmental Management
ITC	Imputed Tax Credit
IPALCO	IPALCO Enterprises, Inc.

IPL	Indiana, Indianapolis Power & Light Company
IPP	Independent Power Producers
I-SEM	Integrated Single Electricity Market
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission
LIBOR	London Inter Bank Offered Rate
LNG	Liquefied Natural Gas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MRE	Energy Reallocation Mechanism
MW	Megawatts
MWh	Megawatt Hours
NAAQS	National Ambient Air Quality Standards
NCI	Noncontrolling Interest
NCRE	Non-Conventional Renewable Energy
NEK	Natsionalna Elektricheska Kompania (state-owned electricity public supplier in Bulgaria)
NEPCO	National Electric Power Company
NERC	North American Electric Reliability Corporation
NM	Not Meaningful
NOV	Notice of Violation
NO_X	Nitrogen Dioxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OERC	Orissa Electricity Regulatory Commission
ONS	National System Operator
OPGC	Odisha Power Generation Corporation, Ltd.
OTC Policy	Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling
Parent Company	The AES Corporation
PCU	Performance Cash Units
Pet Coke	Petroleum Coke
PIS	Partially Integrated System
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PPA	Power Purchase Agreement
PREPA	Puerto Rico Electric Power Authority
PSD	Prevention of Significant Deterioration
PSU	Performance Stock Unit
PUCO	The Public Utilities Commission of Ohio
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying Facility
RMRR	Routine Maintenance, Repair and Replacement
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
SADI	Argentine Interconnected System
SBU	Strategic Business Unit
SCE	Southern California Edison
SEC	United States Securities and Exchange Commission
SEM	Single Electricity Market
SEN	Sistema Electrico Nacional
SIC	Central Interconnected Electricity System
SIN	National Interconnected System
SING	Northern Interconnected Electricity System
SIP	State Implementation Plan
SNE	National Secretary of Energy
SO_2	Sulfur Dioxide
SSO	Standard Service Offer
SWRCB	California State Water Resources Board
TCJA	Tax Cuts and Jobs Act
TECONS	Term Convertible Preferred Securities
U.S.	United States
UK	United Kingdom
USD	U.S. dollar

VAT	Value Added Tax
VIE	Variable Interest Entity
Vinacomin	Vietnam National Coal-Mineral Industries Holding Corporation Ltd.
YPF	Argentina state-owned gas company

PART I

In this Annual Report the terms "AES," "the Company," "us," or "we" refer to The AES Corporation and all of its subsidiaries and affiliates, collectively. The terms "The AES Corporation" and "Parent Company" refer only to the parent, publicly held holding company, The AES Corporation, excluding its subsidiaries and affiliates.

FORWARD-LOOKING INFORMATION

In this filing we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Although we believe that these forward-looking statements and the underlying assumptions are reasonable, we cannot assure you that they will prove to be correct.

Forward-looking statements involve a number of risks and uncertainties, and there are factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements. Some of those factors (in addition to others described elsewhere in this report and in subsequent securities filings) include:

- the economic climate, particularly the state of the economy in the areas in which we operate and the state of the economy in China, which impacts demand for electricity in many of our key markets, including the fact that the global economy faces considerable uncertainty for the foreseeable future, which further increases many of the risks discussed in this Form 10-K;
- changes in inflation, demand for power, interest rates and foreign currency exchange rates, including our ability to hedge our interest rate and foreign currency risk;
- changes in the price of electricity at which our generation businesses sell into the wholesale market and our utility businesses purchase to distribute to their customers, and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk;
- changes in the prices and availability of coal, gas and other fuels (including our ability to have fuel transported to our facilities) and the success of our risk management practices, such as our ability to hedge our exposure to such market price risk, and our ability to meet credit support requirements for fuel and power supply contracts;
- changes in and access to the financial markets, particularly changes affecting the availability and cost of capital in order to refinance existing debt and finance capital expenditures, acquisitions, investments and other corporate purposes;
- our ability to fulfill our obligations, manage liquidity and comply with covenants under our recourse and non-recourse debt, including our ability to manage our significant liquidity needs and to comply with covenants under our senior secured credit facility and other existing financing obligations;
- our ability to receive funds from our subsidiaries by way of dividends, fees, interest, loans or otherwise;
- changes in our or any of our subsidiaries' corporate credit ratings or the ratings of our or any of our subsidiaries' debt securities or preferred stock, and changes in the rating agencies' ratings criteria;
- our ability to purchase and sell assets at attractive prices and on other attractive terms;
- our ability to compete in markets where we do business;
- our ability to operate power generation, distribution and transmission facilities, including managing availability, outages and equipment failures;
- our ability to manage our operational and maintenance costs, the performance and reliability of our generating plants, including our ability to reduce unscheduled down times;
- our ability to enter into long-term contracts, which limit volatility in our results of operations and cash flow, such as PPAs, fuel supply, and other agreements and to manage counterparty credit risks in these agreements;
- variations in weather, especially mild winters and cooler summers in the areas in which we operate, the occurrence of difficult hydrological conditions for our hydropower plants, as well as hurricanes and other storms and disasters, wildfires and low levels of wind or sunlight for our wind and solar facilities;
- the performance of our contracts by our contract counterparties, including suppliers or customers;
- severe weather and natural disasters;
- our ability to raise sufficient capital to fund development projects or to successfully execute our development projects;
- the success of our initiatives in other renewable energy projects and energy storage projects;

- the availability of government incentives or policies that support the development of renewable energy generation projects;
- our ability to keep up with advances in technology;
- growth in number of customers or in customer usage;
- the operations of our joint ventures that we do not control;
- our ability to achieve reasonable rate treatment in our utility businesses;
- changes in laws, rules and regulations affecting our international businesses, particularly in developing countries;
- changes in laws, rules and regulations affecting our utilities businesses, including, but not limited to, regulations which may affect competition, the ability to recover net utility assets and other potential stranded costs by our utilities;
- changes in law resulting from new local, state, federal or international energy legislation and changes in political or regulatory oversight or incentives affecting our wind business and solar projects, our other renewables projects and our initiatives in GHG reductions and energy storage, including government policies or tax incentives;
- changes in environmental laws, including requirements for reduced emissions, GHG legislation, regulation, and/or treaties and CCR regulation and remediation;
- changes in tax laws, including U.S. tax reform, and challenges to our tax positions;
- the effects of litigation and government and regulatory investigations;
- the performance of our acquisitions;
- our ability to maintain adequate insurance;
- decreases in the value of pension plan assets, increases in pension plan expenses, and our ability to fund defined benefit pension and other postretirement plans at our subsidiaries;
- losses on the sale or write-down of assets due to impairment events or changes in management intent with regard to either holding or selling certain assets;
- changes in accounting standards, corporate governance and securities law requirements;
- our ability to maintain effective internal controls over financial reporting;
- our ability to attract and retain talented directors, management and other personnel, including, but not limited to, financial personnel in our foreign businesses that have extensive knowledge of accounting principles generally accepted in the United States; and
- cyber-attacks and information security breaches.

These factors in addition to others described elsewhere in this Form 10-K, including those described under Item 1A.—*Risk Factors*, and in subsequent securities filings, should not be construed as a comprehensive listing of factors that could cause results to vary from our forward-looking information.

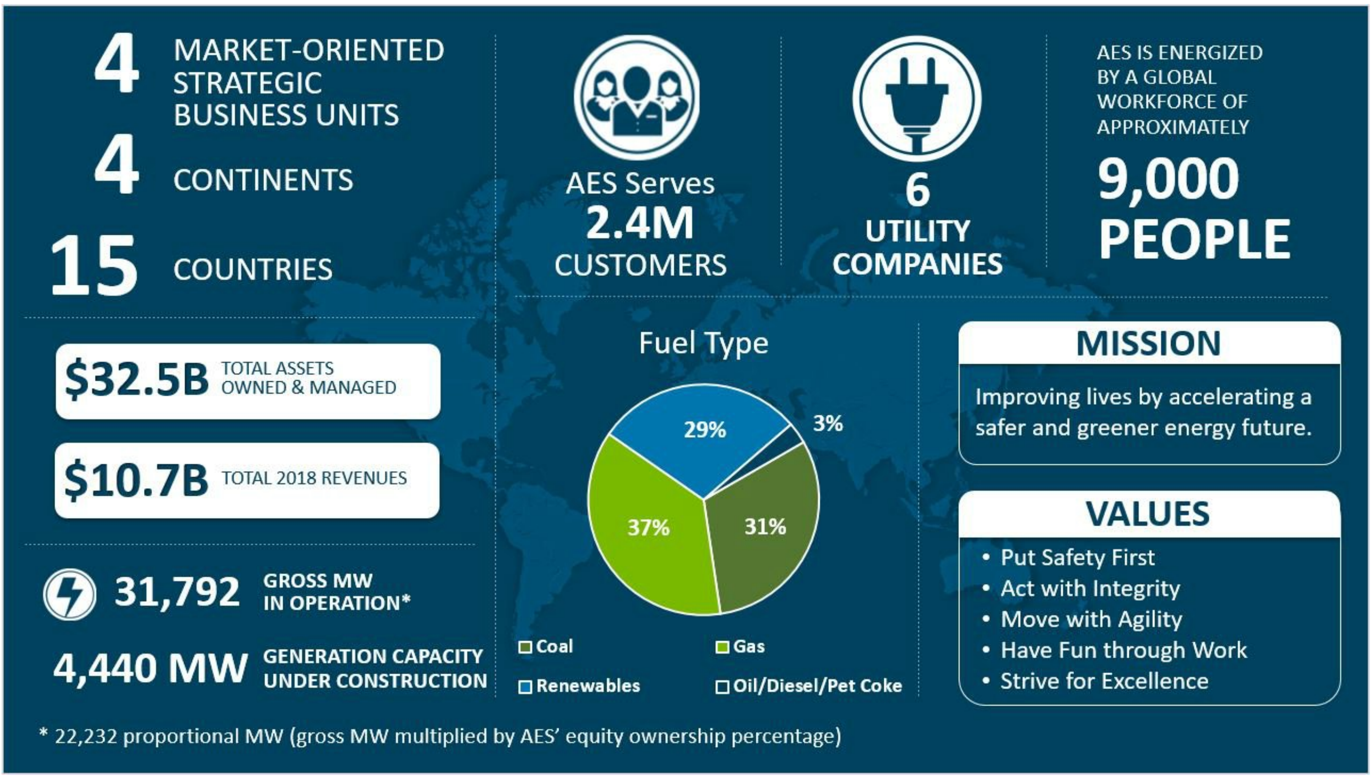
We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise. If one or more forward-looking statements are updated, no inference should be drawn that additional updates will be made with respect to those or other forward-looking statements.

ITEM 1. BUSINESS

Item 1.—*Business* is an outline of our strategy and our businesses by SBU, including key financial drivers. Additional items that may have an impact on our businesses are discussed in Item 1A.—*Risk Factors* and Item 3.—*Legal Proceedings*.

Executive Summary

Incorporated in 1981, AES is a power generation and utility company, providing affordable, sustainable energy through our diverse portfolio of thermal and renewable generation facilities and distribution businesses. Our mission is to improve lives by accelerating a safer and greener energy future. We do this by leveraging our unique electricity platforms and the knowledge of our people to provide the energy and infrastructure solutions our customers need. Our people share a passion to help meet the world's current and increasing energy needs, while providing communities and countries the opportunity for economic growth through the availability of reliable, affordable electric power.



Overview of Our Strategy

Future growth across our company will be heavily weighted toward less carbon-intensive wind, solar and natural gas generation and infrastructure. Our robust backlog of projects under construction or under signed PPAs continues to increase, driven by our focus on select markets where we can take advantage of our global scale and synergies with our existing businesses. In 2018, we signed long-term PPAs for 2 GW of capacity and we are on pace to sign 2 to 3 GW of new PPAs annually through 2022.

We are also working on enhancing some of our current contracts by blending and extending existing PPAs and by adding renewable energy. We call this approach Green Blend and Extend. With this strategy, we leverage our existing platforms, contracts and relationships to negotiate new long-term renewable PPAs with higher returns than we would otherwise achieve through a bidding process. We see potential opportunities to execute this strategy across many of our markets, including Chile, Mexico and the United States.

In Hawaii, we are delivering pioneering solar plus storage facilities, which will serve baseload energy needs, including satisfying demand with renewable power 24 hours a day, seven days a week.

We have two LNG regasification terminals in Central America and the Caribbean, with a total of 150 TBTU of LNG storage capacity. These terminals were built to supply not only the gas for our co-located combined cycle plants, but also to meet the growing demand for natural gas in the region.

In Panama, the storage tank at our recently inaugurated Colon power plant and regasification terminal is expected to come on-line in mid-2019. We believe there is significant potential upside associated with increasing utilization beyond the requirements of our co-located power plant.

As a result of our efforts to decrease our exposure to coal-fired generation and increase our portfolio of renewables, energy storage and natural gas capacity, we are significantly reducing our carbon dioxide emissions per MWh of generation. Under our current strategy, we anticipate a reduction of carbon intensity levels of 50% from 2016 to 2022 and of 70% from 2016 to 2030.

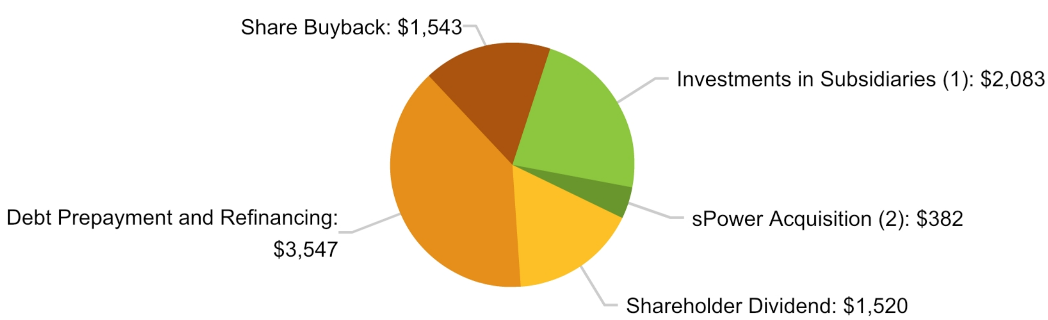
We are a leader in deploying new technologies, such as battery-based energy storage, drone applications and digital customer interfaces. The Company's energy storage joint venture with Siemens, Fluence, has now delivered or been awarded 80 projects in 18 countries, with a total capacity of 766 MW.

Strategic Highlights

We continue to improve the returns from our existing portfolio and position AES for long-term, sustainable growth.

- In 2018, the Company paid down $1 billion in Parent debt
  - Reduced Parent debt by 22%, to $3.7 billion, compared to December 31, 2017
  - In December 2018, the Company achieved a key investment grade financial metric of 3.95x Parent leverage one year earlier than previously planned
- As of December 31, 2018, the Company's backlog of 5,787 MW includes:
  - 3,841 MW under construction and coming on-line through 2021; and
  - 1,946 MW of renewables signed under long-term PPAs
- In 2018, the Company agreed to sell approximately 48% of its interest in sPower's operating portfolio
  - Once these sales close, AES' ownership in sPower's operating portfolio will decrease from 50% to approximately 26%
- In 2018, the Company signed long-term agreements to sell 25 TBTU of LNG annually in the Dominican Republic, which will contribute to growth beyond 2020
- In 2018, Fluence was awarded 286 MW of new projects

Allocation of $9.1 Billion in Discretionary Cash
(September 2011 - December 2018, $ in Millions)



(1) Investments in subsidiaries excludes $2.2 billion investment in DPL

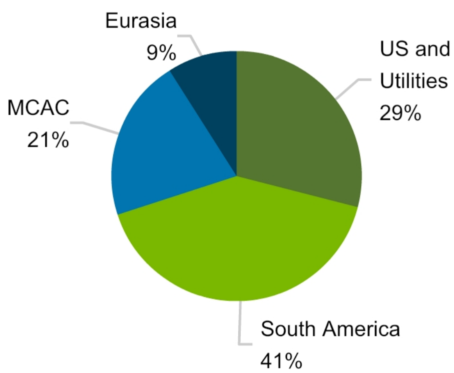
(2) Excludes working capital adjustments and growth activity prior to the close of the acquisition.

Segments

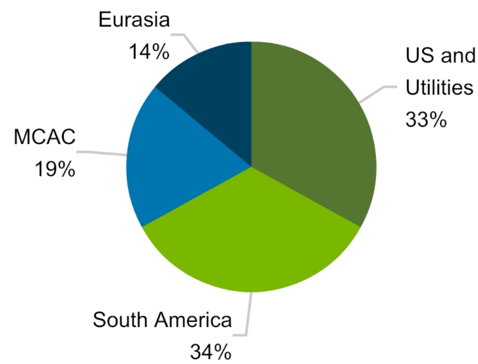
We are organized into four market-oriented SBUs: **US and Utilities** (United States, Puerto Rico and El Salvador); **South America** (Chile, Colombia, Argentina and Brazil); **MCAC** (Mexico, Central America and the Caribbean); and **Eurasia** (Europe and Asia) — which are led by our SBU Presidents. During the first quarter of 2018, the Andes and Brazil SBUs were merged in order to leverage scale and are now reported together as part of the South America SBU. Further, the Puerto Rico and El Salvador businesses, formerly part of the MCAC SBU, were combined with the US SBU, which is now reported as the US and Utilities SBU. Within our four SBUs, we have two lines of business. The first business line is generation, where we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. The second business line is utilities, where we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market.

We measure the operating performance of our SBUs using Adjusted PTC, a non-GAAP measure. The Adjusted PTC by SBU for the year ended December 31, 2018 is shown below. The percentages for Adjusted PTC are the contribution by each SBU to the gross metric, i.e., the total Adjusted PTC by SBU, before deductions for Corporate. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations —SBU Performance Analysis* of this Form 10-K for reconciliation and definitions of Adjusted PTC.

Operating Margin



Adjusted PTC



The following summarizes our businesses within our four SBUs.

US and Utilities

Generation Facilities and Utilities in the United States and El Salvador

29 GENERATION FACILITIES

11,574 GROSS MW

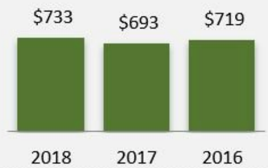
6 UTILITY COMPANIES

26,020 GWH

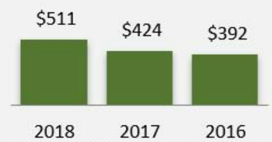
UNDER CONSTRUCTION

10 PLANTS : **1,907 MW**

Operating Margin (in millions)



Adjusted PTC (in millions)



KEY GENERATION BUSINESSES: sPower, Southland, AES Distributed Energy and Warrior Run
KEY UTILITIES: IPL, DPL, and El Salvador

KEY EVENTS

- IPL and DPL successfully completed their distribution rate cases with orders from Commissions
- Closed on sale of DPL Peaker assets
- Completed 671 MW Eagle Valley CCGT in Indiana
- Signed agreement to sell Shady Point in Oklahoma, pending regulatory approval

OUTLOOK

- Expected growth in renewables portfolio
- AES Southland Re-Powering
- Monitor and navigate PREPA bankruptcy in Puerto Rico

South America

Generation Facilities in Chile, Colombia, Argentina and Brazil

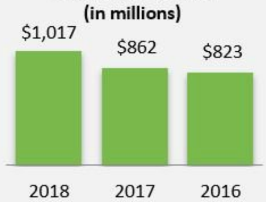
51 GENERATION FACILITIES

12,435 GROSS MW

UNDER CONSTRUCTION

5 PLANTS : **855 MW**

Operating Margin (in millions)



Adjusted PTC (in millions)

KEY GENERATION BUSINESSES: AES Gener, Chivor, AES Argentina, and Tietê

KEY EVENTS

- Closed on sale of Eletropaulo in Brazil
- Completed acquisition of 150 MW Guaimbê Solar Complex in Brazil
- Signed first Green Blend and Extend contract for 270 MW in Chile

OUTLOOK

- Advance Green Blend and Extend strategy, to help meet growing demand for renewables in Chile
- Complete projects under construction, including Alto Maipo in Chile

MCAC

Generation Facilities in the Dominican Republic, Mexico and Panama

17 GENERATION FACILITIES

3,205 GROSS MW

UNDER CONSTRUCTION

1 PLANT : **306 MW**

KEY GENERATION BUSINESSES: Andres-Los Mina, Panama and TEG TEP

KEY EVENTS

- Commencement of operations at the 381 MW Colon CCGT
- Signed long-term agreements for 25 TBTU of excess LNG capacity annually in the Dominican Republic

OUTLOOK

- Completion of LNG storage tank at Colon to help meet growing need for natural gas in Central America and the Caribbean
- Complete construction of Mesa La Paz Green Blend and Extend wind project in Mexico

Eurasia

Generation Facilities in Bulgaria, India, Jordan, the Netherlands, the United Kingdom, and Vietnam

11 GENERATION FACILITIES

4,578 GROSS MW

UNDER CONSTRUCTION

2 PLANTS : **1,372 MW**

KEY GENERATION BUSINESSES: Maritza, Mong Duong, and OPGC I

KEY EVENTS

- Closed on sale of Philippines businesses
- Northern Ireland market reform

OUTLOOK

- OPGC 2 expansion projects to contribute to longer-term growth
- Complete construction of solar project in Jordan

Overview

Generation

We currently own and/or operate a generation portfolio of 31,792 MW, including one integrated utility. Our generation fleet is diversified by fuel type. See discussion below under *Fuel Costs*.

Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, availability of generation capacity to meet contracted sales, fuel costs, seasonality, weather variations and economic activity, fixed-cost management, and competition.

Contract Sales — Most of our generation businesses sell electricity under medium- or long-term contracts ("contract sales") or under short-term agreements in competitive markets ("short-term sales"). Our medium-term contract sales have terms of two to five years, while our long-term contracts have terms of more than five years.

In contract sales, our generation businesses recover variable costs, including fuel and variable O&M costs, either through direct or indexation-based contractual pass-throughs or tolling arrangements. When the contract does not include a fuel pass-through, we typically hedge fuel costs or enter into fuel supply agreements for a similar contract period (see discussion below under *Fuel Costs*). These contracts are intended to reduce exposure to the volatility of fuel and electricity prices by linking the business's revenues and costs. These contracts also help us to fund a significant portion of the total capital cost of the project through long-term non-recourse project-level financing.

Capacity Payments in Contract Sales — Most of our contract sales include a capacity payment that covers projected fixed costs of the plant, including fixed O&M expenses, and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payment be denominated in the currency matching our fixed costs. We generally structure our business to eliminate or reduce foreign exchange risk by matching the currency of revenue and expenses, including fixed costs and debt. Our project debt may consist of both fixed and floating rate debt for which we typically hedge a significant portion of our exposure. Some of our contracted businesses also receive a regulated market-based capacity payment, which is discussed in more detail in the *Short-Term Sales* and *Capacity Payments* sections below.

Thus, these contracts, or other related commercial arrangements, significantly mitigate our exposure to changes in power and fuel prices, currency fluctuations and changes in interest rates. In addition, these contracts generally provide for a recovery of our fixed operating expenses and a return on our investment, as long as we operate the plant to the reliability and efficiency standards required in the contract.

Short-Term Sales — Our other generation businesses sell power and ancillary services under short-term contracts with average terms of less than two years, including spot sales, directly in the short-term market or at regulated prices. The short-term markets are typically administered by a system operator to coordinate dispatch. Short-term markets generally operate on merit order dispatch, where the least expensive generation facilities, based upon variable cost or bid price, are dispatched first and the most expensive facilities are dispatched last. The short-term price is typically set at the marginal cost of energy or bid price (the cost of the last plant required to meet system demand). As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system. Across our portfolio, we provide a wide array of ancillary services, including voltage support, frequency regulation and spinning reserves.

Capacity Payments — Many of the markets in which we operate include regulated capacity markets. These capacity markets are intended to provide additional revenue based upon availability without reliance on the energy margin from the merit order dispatch. Capacity markets are typically priced based on the cost of a new entrant and the system capacity relative to the desired level of reserve margin (generation available in excess of peak demand). Our generating facilities selling in the short-term markets typically receive capacity payments based on their availability in the market.

Plant Reliability and Flexibility — Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under contract sales are frequently tied to meeting minimum standards. In short-term sales, our plants must be reliable and flexible to capture peak market prices and to maximize market-based revenues. In addition, our flexibility allows us to capture ancillary service revenue while meeting local market needs.

Fuel Costs — For our thermal generation plants, fuel is a significant component of our total cost of generation. For contract sales, we often enter into fuel supply agreements to match the contract period, or we may hedge our fuel costs. Some of our contracts have periodic adjustments for changes in fuel cost indices. In those cases, we have fuel supply agreements with shorter terms to match those adjustments. For certain projects, we have tolling arrangements where the power offtaker is responsible for the supply and cost of fuel to our plants.

In short-term sales, we sell power at market prices that are generally reflective of the market cost of fuel at the time, and thus procure fuel supply on a short-term basis, generally designed to match up with our market sales profile. Since fuel price is often the primary determinant for power prices, the economics of projects with short-term sales are often subject to volatility of relative fuel prices. For further information regarding commodity price risk please see Item 7A.—*Quantitative and Qualitative Disclosures about Market Risk* in this Form 10-K.

37% of the capacity of our generation plants are fueled by natural gas. Generally, we use gas from local suppliers in each market. A few exceptions to this are AES Gener in Chile, where we purchase imported gas from third parties, and our plants in the Dominican Republic, where we import LNG to utilize in the local market.

31% of the capacity of our generation fleet is coal-fired. In the U.S., most of our plants are supplied from domestic coal. At our non-U.S. generation plants, and at our plant in Hawaii, we source coal internationally. Across our fleet, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement.

29% of the capacity of our generation plants are fueled by renewables, including hydro, solar, wind, energy storage, biomass and landfill gas, which do not have significant fuel costs.

3% of the capacity of our generation fleet utilizes pet coke, diesel or oil for fuel. Oil and diesel are sourced locally at prices linked to international markets, while pet coke is largely sourced from Mexico and the U.S.

Seasonality, Weather Variations and Economic Activity — Our generation businesses are affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations, including temperature, solar and wind resources, and hydrological conditions, may also have an impact on generation output at our renewable generation facilities. In competitive markets for power, local economic activity can also have an impact on power demand and short-term prices for power.

Fixed-Cost Management — In our businesses with long-term contracts, the majority of the fixed O&M costs are recovered through the capacity payment. However, for all generation businesses, managing fixed costs and reducing them over time is a driver of business performance.

Competition — For our businesses with medium- or long-term contracts, there is limited competition during the term of the contract. For short-term sales, plant dispatch and the price of electricity are determined by market competition and local dispatch and reliability rules.

Utilities

AES' six utility businesses distribute power to 2.4 million people in two countries. AES' two utilities in the U.S. also include generation capacity totaling 4,102 MW. Our utility businesses consist of IPL (an integrated utility) and DP&L (transmission and distribution) in the U.S., and four utilities in El Salvador (distribution).

In general, our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. Key performance drivers for utilities include the regulated rate of return and tariff, seasonality, weather variations, economic activity, reliability of service and competition. Revenue from utilities is classified as regulated on the Consolidated Statements of Operations.

Regulated Rate of Return and Tariff — In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices ("tariffs") that our utilities are allowed to charge customers for electricity and establishes service standards that we are required to meet.

Our utilities are generally permitted to earn a regulated rate of return on assets, determined by the regulator based on the utility's allowed regulatory asset base, capital structure and cost of capital. The asset base on which the utility is permitted a return is determined by the regulator and is based on the amount of assets that are considered used and useful in serving customers. Both the allowed return and the asset base are important components of the utility's earning power. The allowed rate of return and operating expenses deemed reasonable by the regulator are recovered through the regulated tariff that the utility charges to its customers.

The tariff may be reviewed and reset by the regulator from time to time depending on local regulations, or the utility may seek a change in its tariffs. The tariff is generally based upon usage level and may include a pass-through of costs that are not controlled by the utility, such as the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, to the customer. Components of the tariff that are directly passed through to the customer are usually adjusted through a summary regulatory process or an existing formula-based mechanism. In some regulatory regimes, customers with demand above an established level are unregulated and can choose to contract with other retail energy suppliers directly and pay non-bypassable fees, which are fees to the distribution company for use of its distribution system.

The regulated tariff generally recognizes that our utility businesses should recover certain operating and fixed costs, as well as manage uncollectible amounts, quality of service and non-technical losses. Utilities, therefore, need to manage costs to the levels reflected in the tariff, or risk non-recovery of costs or diminished returns.

Seasonality, Weather Variations, and Economic Activity — Our utility businesses are affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations may also have an impact based on the number of customers, temperature variances from normal conditions, and customers' historic usage levels and patterns. Retail sales, after adjustments for weather variations, are affected by changes in local economic activity, energy efficiency and distributed generation initiatives, as well as the number of retail customers.

Reliability of Service — Our utility businesses must meet certain reliability standards, such as duration and frequency of outages. Those standards may be explicit, with defined performance incentives or penalties, or implicit, where the utility must operate to meet customer expectations.

Competition — Our fully integrated utility, IPL, and our transmission and distribution regulated utility, DP&L, operate as the sole distributors of electricity within their respective jurisdictions. IPL owns and operates all of the businesses and facilities necessary to generate, transmit and distribute electricity. DP&L owns and operates all of the businesses and facilities necessary to transmit and distribute electricity. Competition in the regulated electricity business is primarily from the on-site generation for industrial customers. IPL is exposed to the volatility in wholesale prices to the extent our generating capacity exceeds the native load served under the regulated tariff and short-term contracts. However, effective with the approval of the 2018 IPL rate order in December, annual wholesale margins earned above or below a certain benchmark are shared with customers, thus mitigating this volatility. See the full discussion under the US and Utilities SBU.

At our distribution business in El Salvador, we face limited competition due to significant barriers to enter the market. According to El Salvador's regulation, large regulated customers have the option of becoming unregulated users and requesting service directly by the generation or commercialization agents.

Development and Construction

We develop and construct new generation facilities. For our utility business, new plants may be built or existing plants retrofitted in response to customer needs or to comply with regulatory developments. The projects are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is platform expansion opportunities, where we can add on to our existing facilities in our key platform markets where we have a competitive advantage. We make the decision to invest in new projects by evaluating the project returns and financial profile against a fair risk-adjusted return for the investment and against alternative uses of capital, including corporate debt repayment and share buybacks.

In some cases, we enter into long-term contracts for output from new facilities prior to commencing construction. To limit required equity contributions from The AES Corporation, we also seek non-recourse project debt financing and other sources of capital, including partners where it is commercially attractive. We typically contract with a third party to manage construction, although our construction management team supervises the construction work and tracks progress against the project's budget and the required safety, efficiency and productivity standards.

Segments

The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the business internally. It is organized by geographic regions which provide a socio-political-economic understanding of our business. For financial reporting purposes, the Company's corporate activities are reported within "Corporate and Other" because they do not require separate disclosure. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and Note 15—*Segment and Geographic Information* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of the Company's segment structure.

US AND UTILITIES SBU

Our US and Utilities SBU has 29 generation facilities, two utilities in the United States, and four utilities in El Salvador.

Generation — Operating installed capacity of our US and Utilities SBU totals 11,574 MW. IPALCO (IPL's parent), DP&L, and DPL Inc. (DP&L's parent) are all SEC registrants, and as such, follow the public filing requirements of the Securities Exchange Act of 1934. The following table lists our US and Utilities SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Bosforo	El Salvador	Solar	43	50%	2018	2043	EEO
AES Nejapa	El Salvador	Landfill Gas	6	100%	2011	2035	CAESS
Moncagua	El Salvador	Solar	3	100%	2015	2035	EEO
El Salvador Subtotal			**52**				
Southland—Alamitos	US-CA	Gas	2,075	100%	1998	2019-2020	Southern California Edison
Southland—Redondo Beach	US-CA	Gas	1,392	100%	1998	2020	EDF Energy, LLC, Clean Power Alliance of Southern California
sPower [1]	US-Various	Solar	1,081	50%	2017-2018	2028-2046	Various
AES Puerto Rico	US-PR	Coal	524	100%	2002	2027	Puerto Rico Electric Power Authority
Southland—Huntington Beach	US-CA	Gas	474	100%	1998	2019-2020	Southern California Edison
Shady Point [2]	US-OK	Coal	360	100%	1991		
Buffalo Gap II [3]	US-TX	Wind	233	100%	2007		
Hawaii	US-HI	Coal	206	100%	1992	2022	Hawaiian Electric Co.
Warrior Run	US-MD	Coal	205	100%	2000	2030	First Energy
Buffalo Gap III [3]	US-TX	Wind	170	100%	2008		
sPower [1]	US-Various	Wind	140	50%	2017	2036	Various
AES Distributed Energy (AES DE) [3]	US-Various	Solar	136	100%	2015-2018	2029-2042	Utility, Municipality, Education, Non-Profit
Buffalo Gap I [3]	US-TX	Wind	117	100%	2006	2021	Direct Energy
Laurel Mountain	US-WV	Wind	98	100%	2011		
Mountain View I & II	US-CA	Wind	65	100%	2008	2021	Southern California Edison
Mountain View IV	US-CA	Wind	49	100%	2012	2032	Southern California Edison
Lawa'i (AES DE) [3]	US-HI	Solar Energy Storage	20 20	100%	2018	2043	Kaua'i Island Utility Cooperative
Ilumina	US-PR	Solar	24	100%	2012	2032	Puerto Rico Electric Power Authority
Laurel Mountain ES	US-WV	Energy Storage	16	100%	2011		
AES Gilbert (Salt River)	US-AZ	Energy Storage	10	100%	2019	2039	Salt River Project Agricultural Improvement and Power District
Warrior Run ES	US-MD	Energy Storage	5	100%	2016		
United States Subtotal			**7,420**				
			7,472				

(1) Unconsolidated entity, accounted for as an equity affiliate.

(2) Announced the sale of this business in December 2018.

(3) AES owns these assets together with third-party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as noncontrolling interest in the Company's Consolidated Balance Sheets.

Under construction — The following table lists our plants under construction in the US and Utilities SBU:

Business	Location	Fuel	Gross	AES Equity	Expected Date of Commercial
AES Distributed Energy (AES DE)	US-Various	Solar	47	100%	1H-2H 2019
		Energy Storage	3	100%	2H 2019
Riverhead (sPower)	US-NY	Solar	20	50%	1H 2019
Bosforo	El Salvador	Solar	57	50%	1H 2019
Basin Electric (sPower)	US-SD	Wind	220	50%	2H 2019
San Pablo (sPower)	US-CA	Solar	100	50%	2H 2019
Antelope DSR3 (sPower)	US-CA	Solar	20	50%	2H 2019
Kekaha (AES DE)	US-HI	Solar	14	100%	2H 2019
		Energy Storage	14	100%	
Southland Repowering	US-CA	Gas	1,284	100%	1H 2020
Na Pua Makani	US-HI	Wind	28	100%	1H 2020
Alamitos Energy Center	US-CA	Energy Storage	100	100%	1H 2021
			1,907		

Utilities — The following table lists our utilities and their generation facilities.

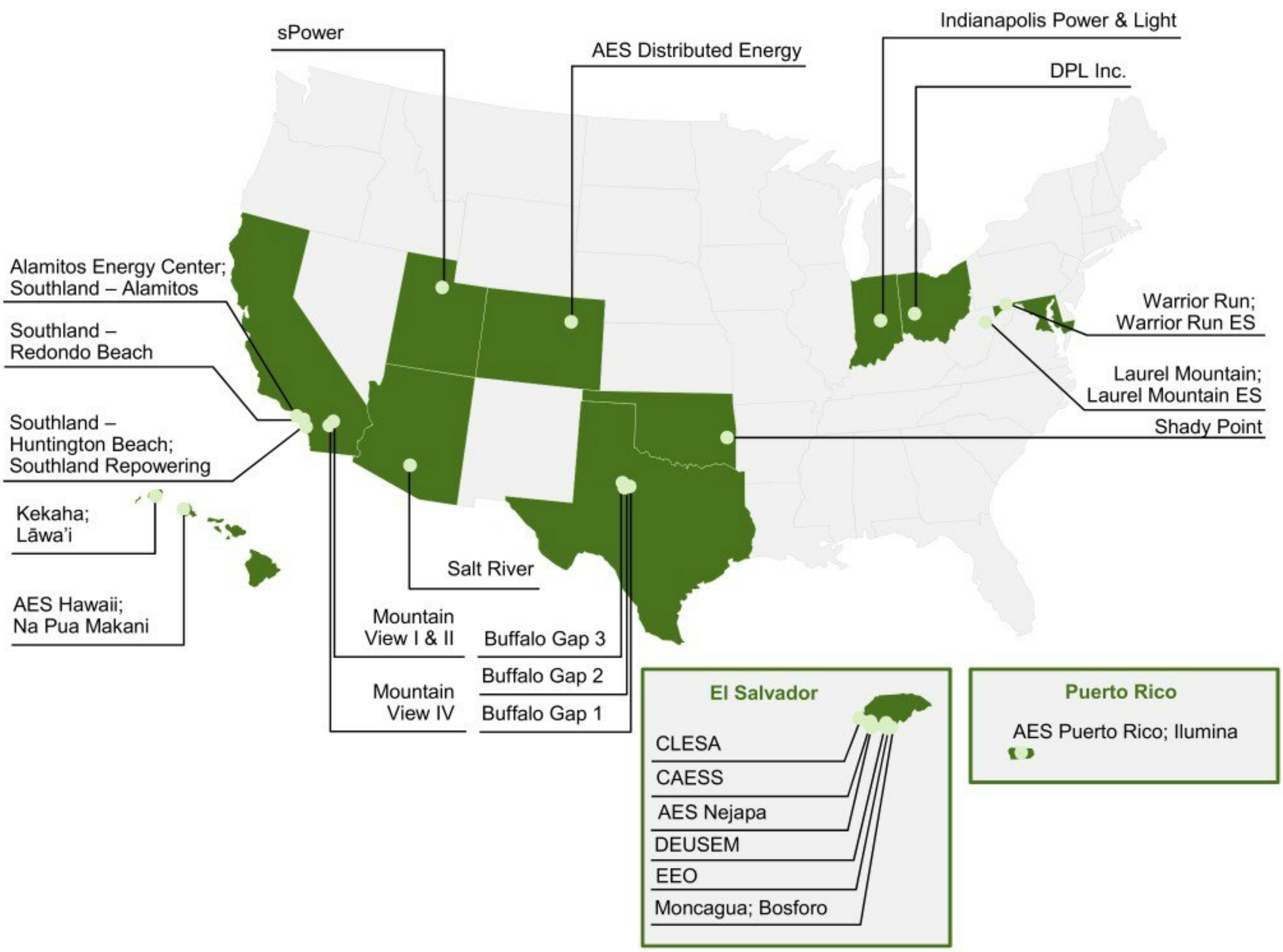
Business	Location	Approximate Number of Customers Served as of 12/31/2018	GWh Sold in 2018	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation
CAESS	El Salvador	602,000	2,122			75%	2000
CLESA	El Salvador	404,000	931			80%	1998
DEUSEM	El Salvador	81,000	138			74%	2000
EEO	El Salvador	310,000	598			89%	2000
El Salvador Subtotal		**1,397,000**	**3,789**				
DPL [(1)]	US-OH	525,000	7,139	Coal	129	100%	2011
IPL [(2)]	US-IN	498,000	15,092	Coal/Gas/Oil	3,973	70%	2001
United States Subtotal		**1,023,000**	**22,231**		**4,102**		
		2,420,000	**26,020**				

(1) DPL's subsidiary, AES Ohio Generation, LLC, owned an undivided interest in Conesville Unit 4. In October 2018, the co-owner of Conesville Unit 4 announced that the plant will be retired by May 2020. DPL's subsidiary, DP&L, also owns a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,109 MW. DP&L's share of this generation is approximately 103 MW. DPL's GWh sold in 2018 represent DPL's wholesale revenues and DP&L's Standard Service Offer (SSO) utility revenues, which are sales to utility customers who use DP&L to source their electricity through the competitive bid process. Total transmission sales were 14,439 GWh.

(2) CDPQ owns direct and indirect interests in IPALCO which total approximately 30%. AES owns 85% of AES US Investments and AES US Investments owns 82.35% of IPALCO. IPL plants: Georgetown, Harding Street, Petersburg and Eagle Valley. 20 MW of IPL total is considered a transmission asset.

The following map illustrates the locations of our US and Utilities facilities:

US and Utilities Businesses



U.S. Businesses

IPL

Regulatory Framework and Market Structure — IPL is subject to comprehensive regulation by the IURC with respect to its services and facilities, retail rates and charges, the issuance of long-term securities, and certain other matters. The regulatory authority of the IURC over IPL's business is typical of regulation generally imposed by state public utility commissions. The IURC sets tariff rates for electric service provided by IPL. The IURC considers all allowable costs for ratemaking purposes, including a fair return on assets used and useful to providing service to customers.

IPL's tariff rates consist of basic rates and approved charges. In addition, IPL's rates include various adjustment mechanisms, including, but not limited to: (i) a rider to reflect changes in fuel and purchased power costs to meet IPL's retail load requirements and (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations. These components function somewhat independently of one another, and are subject to review at the same time as any review of IPL's basic rates and charges.

IPL is one of many transmission system owner members in MISO, an RTO which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. MISO operates on a merit order dispatch, considering transmission constraints and other reliability issues to meet the total demand in the MISO region. IPL offers electricity in the MISO day-ahead and real-time markets.

Business Description — IPL is engaged primarily in generating, transmitting, distributing and selling electric energy to retail customers in the city of Indianapolis and neighboring areas within the state of Indiana. IPL has an exclusive right to provide electric service to those customers. IPL's service area covers about 528 square miles with an estimated population of approximately 950,000. IPL owns and operates four generating stations, all within the state of Indiana. IPL's largest generating station, Petersburg, is coal-fired. The second largest station, Harding Street, uses natural gas and fuel oil to power combustion turbines. In addition, IPL operates a 20 MW battery-based energy storage unit at this location, which provides frequency response. The third station, Eagle Valley, is a newly constructed 671 MW CCGT natural gas plant. IPL took operational control and commenced commercial operations of this CCGT plant in April 2018. The fourth station, Georgetown, is a small peaking station that uses natural gas to power combustion turbines.

On October 31, 2018, the IURC issued an order approving an uncontested settlement agreement to increase IPL's annual revenues by $44 million, or 3% (the "2018 Rate Order"). The 2018 Rate Order primarily includes recovery through rates of costs associated with the CCGT at Eagle Valley, completed in the first half of 2018, and other construction projects. New base rates and charges became effective on December 5, 2018. The order also provides customers with approximately $50 million in benefits, including tax reform benefits associated with the TCJA, over a two-year period through a rate adjustment mechanism beginning in March 2019.

Environmental Regulation — For information on compliance with environmental regulations see Item 1.— *United States Environmental and Land-Use Legislation and Regulations*.

Key Financial Drivers — IPL's financial results are driven primarily by retail demand, weather, and outage costs. In addition, IPL's financial results are likely to be driven by many factors, including, but not limited to:

- regulatory outcomes;
- the passage of new legislation, implementation of regulations or other changes in regulation;
- timely recovery of capital expenditures; and
- to a lesser extent, wholesale and capacity prices.

Construction and Development — IPL's construction program is composed of capital expenditures necessary for prudent utility operations and compliance with environmental regulations, along with discretionary investments designed to replace aging equipment or improve overall performance. Additionally, IPL is currently evaluating future investments under the Transmission, Distribution, and Storage System Improvement Charge, for which electric utilities in Indiana can recover costs (including a return) for IURC approved infrastructure improvement plans.

DPL

Regulatory Framework and Market Structure — DPL is an energy holding company whose principal subsidiaries include DP&L and AES Ohio Generation, LLC, both of which operate in Ohio. Electric customers within Ohio are permitted to purchase power under contract from a CRES provider or from their local utility under SSO rates. The SSO generation supply is provided by third parties through a competitive bid process. Ohio utilities have the exclusive right to provide transmission and distribution services in their state-certified territories.

DP&L is regulated by the PUCO for its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio requirements, energy efficiency program requirements, and certain other matters. The PUCO maintains jurisdiction over the delivery of electricity, SSO, and other retail electric services.

While Ohio allows customers to choose retail generation providers, DP&L is required to provide retail generation service at SSO rates to any customer that has not signed a contract with a CRES provider. SSO rates are subject to rules and regulations of the PUCO and are established through a competitive bid process for the supply of power to SSO customers. DP&L's distribution rates are regulated by the PUCO and are established through a traditional cost-based rate-setting process. DP&L is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure and cost of capital. DP&L's rates include various adjustment mechanisms including, but not limited to, the timely recovery of costs incurred to comply with alternative energy, renewables, energy efficiency, and economic development costs. DP&L's wholesale transmission rates are regulated by FERC.

DP&L is a member of PJM, an RTO that operates the transmission systems owned by utilities operating in all or parts of Pennsylvania, New Jersey, Maryland, Delaware, D.C., Virginia, Ohio, West Virginia, Kentucky, North

Carolina, Tennessee, Indiana and Illinois. PJM also runs the day-ahead and real-time energy markets, ancillary services market and forward capacity market for its members.

Business Description — DP&L transmits, distributes and sells electricity to retail customers in a 6,000 square mile area of West Central Ohio. Ohio consumers have the right to choose the electric generation supplier from whom they purchase retail generation service; however, retail transmission and distribution services are still regulated. DP&L has the exclusive right to provide such transmission and distribution services to those customers. Additionally, DP&L procures retail SSO electric service on behalf of residential, commercial, industrial and governmental customers.

In September 2018, DP&L received an order from the PUCO establishing new base distribution rates for DP&L (“the order”), which became effective October 1, 2018. The order approved, without modification, a stipulation and recommendation previously filed by DP&L, along with various intervening parties, with the PUCO staff. The order established a revenue requirement of $248 million for DP&L's electric service base distribution rates, which reflects an increase to distribution revenues of $30 million per year. In addition, the order authorizes DP&L to collect from customers costs related to qualified investments through a Distribution Investment Rider, changes the Decoupling Rider to reduce variability from the impact of weather and demand, partially resolves regulatory issues related to the TCJA, and authorizes DP&L to defer certain vegetation management costs for future collection.

In January 2019, DP&L filed a request with the PUCO for a two-year extension of its Distribution Modernization Rider ("DMR") through October 2022, in the proposed amount of $199 million for each of the two additional years. The request was made pursuant to the PUCO’s October 2017 ESP order, which approved the DMR and the option for DP&L to file for a two-year extension. The extension request is set at a level expected to reduce debt obligations at both DP&L and DPL and to position DP&L to make capital expenditures to maintain and modernize its electric grid.

Environmental Regulation — For information on compliance with environmental regulations see Item 1.— *United States Environmental and Land-Use Legislation and Regulations.*

Key Financial Drivers — DPL's financial results are primarily driven by customer growth. Following the issuance of the distribution rate order in September 2018 and the resulting changes to the decoupling rider, DPL's financial results are no longer driven by retail demand and weather, but will be impacted by customer growth within our service territory.

In addition, DPL's financial results are likely to be driven by many factors, including, but not limited to:

- the passage of new legislation, new regulations or other changes in regulation;
- timely recovery of transmission and distribution expenditures; and
- exiting generation assets currently owned by AES Ohio Generation.

Construction and Development — Planned construction additions primarily relate to new investments in and upgrades to DPL's transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments, and changing environmental standards, among other factors.

DP&L is projecting to spend an estimated $628 million on capital projects for the period 2019 through 2021. We expect to finance this construction with a combination of cash on hand, short-term financing, long-term debt and cash flows from operations.

In December 2018, DP&L filed a Distribution Modernization Plan with the PUCO proposing to invest $576 million in capital projects over the next 20 years. The principal components of the Distribution Modernization Plan includes leveraging technologies to modernize and improve the sustainability of the grid, and enhancing customer experience and security. These initiatives will allow DP&L to leverage and integrate distributed energy resources into its grid, including community solar, energy storage, microgrids and electric vehicle charging infrastructure.

U.S. Generation

Business Description — In the U.S., we own a diversified generation portfolio in terms of geography, technology and fuel source. The principal markets and locations where we are engaged in the generation and supply of electricity (energy and capacity) are the Western Electric Coordinating Council, PJM, Southwest Power Pool Electric Energy Network and Hawaii. AES Southland, in the Western Electric Coordinating Council, is our most significant generating business.

Many of our U.S. generation plants provide baseload operations and are required to maintain a guaranteed level of availability. Any change in availability has a direct impact on financial performance. The plants are generally eligible for availability bonuses on an annual basis if they meet certain requirements. In addition to plant availability, fuel cost is a key business driver for some of our facilities.

Environmental Regulation — For a discussion of environmental regulatory matters affecting U.S. Generation, see Item 1.—*United States Environmental and Land-Use Legislation and Regulations.*

AES Southland

Business Description — In terms of aggregate installed capacity, AES Southland is one of the largest generation operators in California, with an installed gross capacity of 3,941 MW, accounting for approximately 5% of the state's installed capacity and 17% of the peak demand in Southern California Edison's territory. The three coastal power plants comprising AES Southland are in areas that are critical for local reliability and play an important role in integrating the increasing amounts of renewable generation resources in California.

All of AES Southland's capacity was previously contracted through a 20 year agreement (the “Tolling Agreement”), that expired on May 31, 2018. Currently, AES Huntington Beach, LLC and AES Alamitos, LLC are contracted though Resource Adequacy Purchase Agreements (the “RAPAs”), approved by the California Public Utilities Commission in 2017. AES Redondo Beach, LLC has also entered into various RAPAs for the period of June 1, 2018 through December 31, 2020.

Under the RAPAs, the generating stations provide resource adequacy capacity, and have no obligation to produce or sell any energy to the RAPA counterparty. However, the generating stations are required to bid energy into the California ISO markets. Compensation under these RAPAs is dependent on the availability of the AES Southland units in the California ISO market. Failure to achieve the minimum availability target will result in an assessed penalty.

Re-powering — In November 2014, AES Southland was awarded 20-year contracts by SCE to provide 1,284 MW of combined cycle gas-fired generation and 100 MW of interconnected battery-based energy storage. The contracts are resource adequacy agreements with annual energy put options. If the put option is exercised, all capacity will be sold to SCE in exchange for a fixed monthly capacity fee that covers fixed operating cost, debt service, and return on capital. In addition, SCE will reimburse variable costs and provide the natural gas and charging electricity. If the annual put option is not exercised, SCE only has rights to the resource adequacy capacity for that contract year and AES Southland can sell the energy and ancillary services to other counterparties.

In April 2017, the California Energy Commission unanimously approved the licenses for the new combined cycle projects at AES Alamitos and AES Huntington Beach. In June 2017, AES closed the financing of $2.0 billion, funded with a combination of non-recourse debt and AES equity. The construction of this new capacity started in 2017 and commercial operation of the gas-fired capacity is expected to commence in 2020 and the energy storage capacity is expected to commence in 2021.

Key Financial Drivers — AES Southland's availability is one of the most important drivers of operations along with market prices for gas and electricity.

Additional U.S. Generation Facilities

Regulatory Framework and Market Structure — For the non-renewable businesses, coal and natural gas are used as the primary fuels. Coal prices are set by market factors internationally, while natural gas prices are generally set domestically. Price variations for these fuels can change the composition of generation costs and energy prices in our generation businesses.

Many of these generation businesses have entered into long-term PPAs with utilities or other offtakers. Some businesses with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment partially based on the market price of fuel. When market price fluctuations in fuel are borne by the offtaker, revenue may change as fuel prices fluctuate, but the variable margin or profitability should remain consistent. These businesses often have an opportunity to increase or decrease profitability from payments under their PPAs depending on such items as plant efficiency and availability, heat rate, ability to buy coal at lower costs through AES' global sourcing program and fuel flexibility.

Several of our generation businesses in the U.S. currently operate as QFs, including Hawaii, Shady Point and Warrior Run, as defined under the PURPA. These businesses entered into long-term contracts with electric utilities that had a mandatory obligation to purchase power from QFs at the utility's avoided cost (i.e., the likely costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). To be a QF, a cogeneration facility must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling applications in certain proportions to the facility's total energy output and meet certain efficiency standards. To be a QF, a small power production facility must generally use a renewable resource as its energy input and meet certain size criteria.

Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators as defined under the EPAct 1992. These businesses, subject to approval of FERC, have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the Federal Power Act and FERC's regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller.

The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by FERC, and regional regulation as defined by rules designed and implemented by the RTOs, non-profit corporations that operate the regional transmission grid and maintain organized markets for electricity. These rules, for the most part, govern such items as the determination of the market mechanism for setting the system marginal price for energy and the establishment of guidelines and incentives for the addition of new capacity. See Item 1A.—*Risk Factors* for additional discussion on U.S. regulatory matters.

Business Description — Additional businesses include thermal, wind, and solar generating facilities, of which our U.S. Renewables businesses and AES Hawaii are the most significant.

U.S. Renewables

sPower owns and/or operates 153 utility and distributed electrical generation systems with a capacity of 1,221 MWh currently in operation across the U.S. sPower is also actively buying, developing and constructing renewable assets in the U.S.

AES Distributed Energy develops, constructs and sells electricity generated by photovoltaic solar energy systems and energy storage systems to public sector, utility, and non-profit entities through PPAs.

Excluding sPower wind plants, AES has 732 MW of wind capacity in the U.S., located in California, Texas and West Virginia. Mountain View I & II, Mountain View IV and Buffalo Gap I sell under long-term PPAs through which the energy price on the entire production of these facilities is guaranteed. Laurel Mountain, Buffalo Gap II and Buffalo Gap III are exposed to the volatility of energy prices and their revenue may change materially as energy prices fluctuate in their respective markets of operations.

AES manages the U.S. Renewables portfolio as part of its broader investments in the U.S.. A portion of U.S. Solar projects and the majority of wind projects have been financed with tax equity structures. Under these tax equity structures, the tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes that vary over the life of the projects. Based on certain liquidation provisions of the tax equity structures, this could result in variability to earnings attributable to AES compared to the earnings reported at the facilities.

AES Hawaii

AES Hawaii receives a fuel payment from its offtaker under a PPA expiring in 2022, which is based on a fixed rate indexed to the Gross National Product — Implicit Price Deflator. Since the fuel payment is not directly linked to market prices for fuel, the risk arising from fluctuations in market prices for coal is borne by AES Hawaii. AES Hawaii has entered into fixed-price coal purchase commitments through December 2019 and plans to seek additional fuel purchase commitments to manage fuel price risk after December 2019.

Key Financial Drivers — U.S. thermal generation's financial results are driven by fuel costs and outages. The Company has entered into long-term fuel contracts to mitigate the risks associated with fluctuating prices. In addition, major maintenance requiring units to be off-line is performed during periods when power demand is typically lower. The financial results of U.S. Wind are primarily driven by increased production due to faster and less turbulent wind and reduced turbine outages. In addition, PJM and ERCOT power prices impact financial results for the wind projects that are operating without long-term contracts for all or some of their capacity. The financial results of U.S. Solar are primarily driven by the amount of sunshine hours available at the facilities, cell maintenance and growth in projects. For additional details see *Key Trends and Uncertainties* in Item 7.— *Management's Discussion and Analysis of Financial Condition and Results of Operations*.

Construction and Development — Planned capital projects include the AES Southland re-powering described above. In addition to the new construction project, U.S. Generation performs capital projects related to major plant maintenance, repairs and upgrades to be compliant with new environmental laws and regulations. sPower has 360 MW of projects under construction and a development pipeline that includes 938 MW of projects for which long-term PPAs have been signed. The budget for construction of the projects currently under construction and the contracted projects is over $1.8 billion. AES Distributed Energy has 78 MW of projects under construction and a development pipeline that includes 332 MW of projects for which long-term PPAs have been signed or, as applicable, tariffs have been assigned through a regulatory process. The budget for construction of the projects currently under construction and the contracted projects is over $1 billion.

Puerto Rico

Regulatory Framework and Market Structure — Puerto Rico has a single electric grid managed by PREPA, a state-owned entity that supplies virtually all of the electric power consumed in Puerto Rico and generates, transmits and distributes electricity to 1.5 million customers. The Puerto Rico Energy Bureau is the main regulatory body. The bureau approves wholesale and retail rates, sets efficiency and interconnection standards, and oversees PREPA's compliance with Puerto Rico's renewable portfolio standard.

Puerto Rico's electricity is 98% produced by thermal plants (47% from petroleum, 34% from natural gas, 17% from coal).

Business Description — AES Puerto Rico owns and operates a coal-fired cogeneration plant and a solar plant of 524 MW and 24 MW, respectively, representing approximately 9% of the installed capacity in Puerto Rico. Both plants have long-term PPAs expiring in 2027 and 2032, respectively, with PREPA. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Macroeconomic and Political—Puerto Rico* for further discussion of the long-term PPA with PREPA.

El Salvador

Regulatory Framework and Market Structure — El Salvador's national electric market is composed of generation, distribution, transmission and marketing businesses, as well as a market and system operator and regulatory agencies. The operation of the transmission system and the wholesale market is based on production costs with a marginal economic model that rewards efficiency and allows investors to have guaranteed profits, while end users receive affordable rates. The energy sector is governed by the General Electricity Law, which establishes two regulatory entities responsible for monitoring its compliance:

- The National Energy Council is the highest authority on energy policy and strategy, and the coordinating body for the different energy sectors. One of its main objectives is to promote investment in non-conventional renewable sources to diversify the energy matrix.
- The General Superintendence of Electricity and Telecommunications regulates the market and sets consumer prices, and, jointly with the distribution companies in El Salvador, developed the tariff calculation applicable from 2018 until 2022.

El Salvador has a national electric grid that interconnects with Guatemala and Honduras. The sector has approximately 1,659 MW of installed capacity, composed primarily of thermal (43%), hydroelectric (34%), geothermal (10%), biomass (9%) and solar (4%) generation plants.

Business Description — AES El Salvador is the majority owner of four of the five distribution companies operating in El Salvador (CAESS, CLESA, EEO and DEUSEM). AES El Salvador's territory covers 79% of the country and accounted for 4,040 GWh of the wholesale market energy purchases during 2018, or about 63% market share.

Construction and Development — As part of the initiative to pursue opportunities in renewable generation, AES El Salvador has entered into a joint venture with Corporacion Multi-Inversiones, a Guatemalan investment group, to develop, construct and operate Bosforo, a 142 MW solar farm. 43 MW of the project were completed in 2018 and are fully operational. 57 MW are under construction and expected to become operational during the first half of 2019 and the remaining 42 MW will start construction in 2019 and are expected to be completed in the second half of 2019. The energy produced by this project will be contracted directly by AES' utilities in El Salvador.

South America SBU

Our South America SBU has generation facilities in four countries — Chile, Colombia, Argentina and Brazil. AES Gener, which owns all of our assets in Chile, Chivor in Colombia and TermoAndes in Argentina, as detailed below, is a publicly traded company in Chile. AES has a 66.7% ownership interest in AES Gener and this business is consolidated in our financial statements. Tietê is a publicly traded company in Brazil. AES controls and consolidates Tietê through its 24% economic interest.

Operating installed capacity of our South America SBU totals 12,435 MW, of which 33%, 28%, 8%, and 31% are located in Argentina, Chile, Colombia and Brazil, respectively. The following table lists our South America SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Chivor	Colombia	Hydro	1,000	67%	2000	2019-2026	Various
Tunjita	Colombia	Hydro	20	67%	2016		
Colombia Subtotal			**1,020**				
Gener - Chile [1]	Chile	Coal/Hydro/ Diesel/Solar/ Biomass	1,532	67%	2000	2019-2040	Various
Guacolda [2]	Chile	Coal	760	33%	2000	2019-2032	Various
Electrica Angamos	Chile	Coal	558	67%	2011	2026-2037	Minera Escondida, Minera Spence, Quebrada Blanca
Cochrane	Chile	Coal	550	40%	2016	2030-2037	SQM, Sierra Gorda, Quebrada Blanca
Cochrane ES	Chile	Energy Storage	20	40%	2016		
Electrica Angamos ES	Chile	Energy Storage	20	67%	2011		
Norgener ES (Los Andes)	Chile	Energy Storage	12	67%	2009		
Chile Subtotal			**3,452**				
TermoAndes [3]	Argentina	Gas/Diesel	643	67%	2000	2019-2020	Various
AES Gener Subtotal			**5,115**				
Alicura	Argentina	Hydro	1,050	100%	2000		Various
Paraná-GT	Argentina	Gas/Diesel	870	100%	2001		
San Nicolás	Argentina	Coal/Gas/Oil	675	100%	1993		
Guillermo Brown [4]	Argentina	Gas/Diesel	576	—%	2016		
Los Caracoles [4]	Argentina	Hydro	125	—%	2009	2019	Energia Provincial Sociedad del Estado (EPSE)
Cabra Corral	Argentina	Hydro	102	100%	1995		Various
Ullum	Argentina	Hydro	45	100%	1996		Various
Sarmiento	Argentina	Gas/Diesel	33	100%	1996		
El Tunal	Argentina	Hydro	10	100%	1995		Various
Argentina Subtotal			**3,486**				
Tietê [5]	Brazil	Hydro	2,658	24%	1999	2029	Various
Alto Sertão II	Brazil	Wind	386	24%	2017	2033-2035	Various
Guaimbe	Brazil	Solar	*150*	24%	2018	2037	CCEE
Tietê Subtotal			**3,194**				
Uruguaiana	Brazil	Gas	640	46%	2000		
Brazil Subtotal			**3,834**				
			12,435				

(1) Gener - Chile plants: Alfalfal, Andes Solar, Laguna Verde, Laguna Verde Turbogas, Laja, Maitenes, Norgener 1, Norgener 2, Queltehues, Ventanas 1, Ventanas 2, Ventanas 3, Ventanas 4 and Volcán.

(2) Guacolda is comprised of five coal-fired units under Guacolda Energia S.A., an unconsolidated entity for which the results of operations are reflected in *Net equity in earnings of affiliates*. The Company's ownership in Guacolda is held through AES Gener, a 67%-owned consolidated subsidiary. AES Gener owns 50% of Guacolda, resulting in an AES effective ownership in Guacolda of 33%.

(3) TermoAndes is located in Argentina, but is connected to both the SEN in Chile and the SADI in Argentina.

(4) AES operates these facilities through management or O&M agreements and owns no equity interest in these businesses.

(5) Tietê plants: Água Vermelha, Bariri, Barra Bonita, Caconde, Euclides da Cunha, Ibitinga, Limoeiro, Mog-Guaçu, Nova Avanhandava, Promissão, Sao Joaquim and Sao Jose.

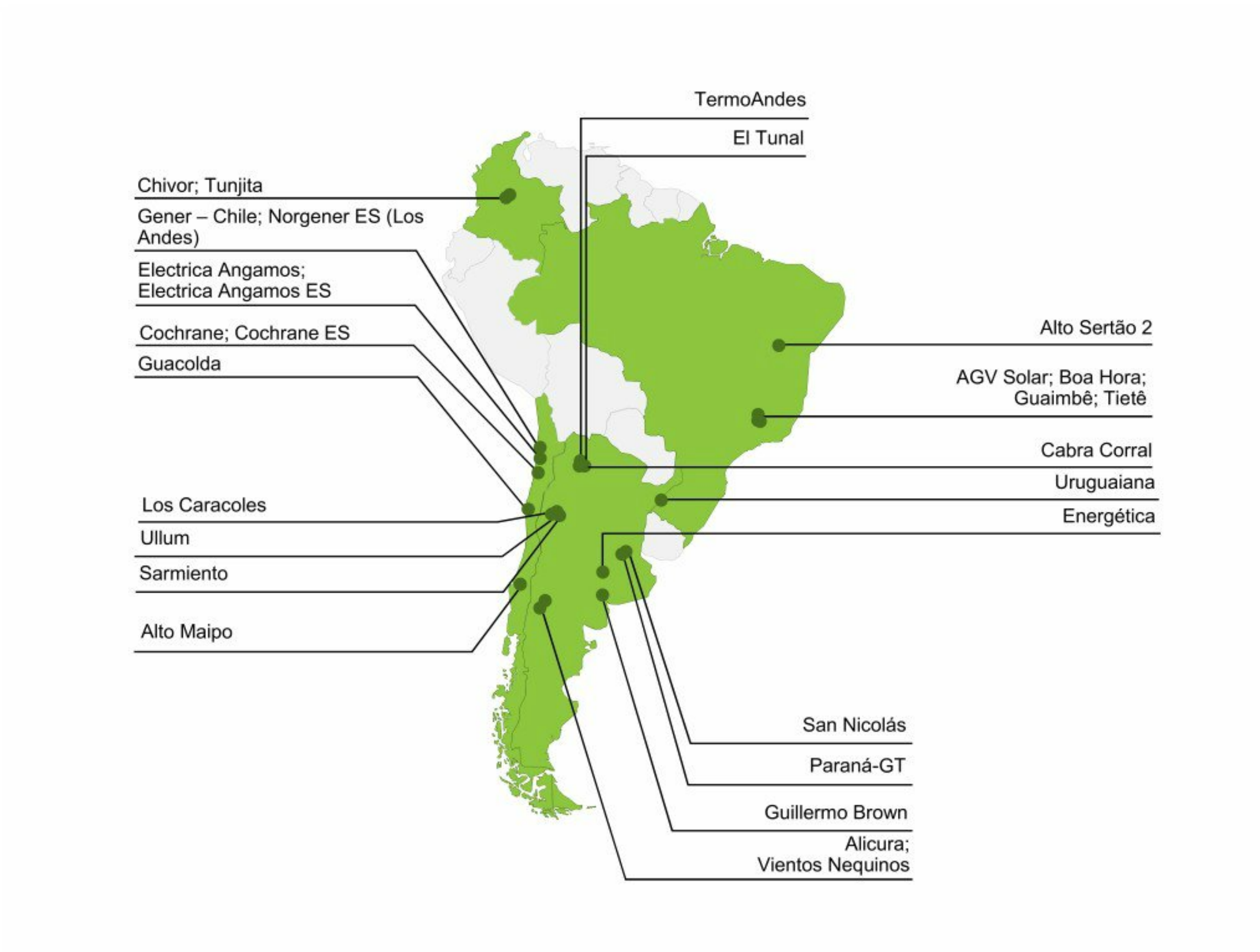
Under construction — The following table lists our plants under construction in the South America SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Boa Hora	Brazil	Solar	69	24%	1H 2019
AGV Solar	Brazil	Solar	75	24%	1H 2019
Energetica	Argentina	Wind	100	100%	1H 2020
Vientos Nequinos	Argentina	Wind	80	100%	1H 2020
Alto Maipo	Chile	Hydro	531	62%	2H 2020
			855		

In June 2018, the Company completed the sale of its entire 17% ownership interest in Eletropaulo, a distribution business in Brazil. Prior to its sale, Eletropaulo was accounted for as an equity method investment and its results of operations and financial position were reported as discontinued operations in the consolidated financial statements for all periods presented.

The following map illustrates the location of our South America facilities:

South America Businesses



Chile

Market Structure and Regulatory Framework — The Chilean electricity industry is divided into three business segments: generation, transmission and distribution. Private companies operate in all three segments, and generators can enter into PPAs to sell energy to regulated and unregulated customers, as well as to other generators in the spot market.

Chile has operated a single power market, referred to as the SEN, which has been managed by the grid operator CEN since November 2017. Previously, Chile had two main power systems, the SIC and SING, largely as a result of its geographic shape and size, which were merged to form the SEN. The SEN has an installed capacity of approximately 24,586 MW. SEN represents 99% of the installed generation capacity of the country.

CEN coordinates all generation and transmission companies in the SEN. CEN minimizes the operating costs of the electricity system, while maximizing service quality and reliability requirements. CEN dispatches plants in merit order based on their variable cost of production, allowing for electricity to be supplied at the lowest available cost. In the south-central region of the SEN (former SIC), thermoelectric generation is required to fulfill demand not satisfied by hydroelectric, solar and wind output and is critical to provide reliable and dependable electricity supply under dry hydrological conditions. In the northern region of the SEN (former SING), which includes the Atacama Desert, thermoelectric capacity represents the majority of installed capacity as hydroelectric generation is not feasible. The fuels used for thermoelectric generation, mainly coal, diesel and LNG, are indexed to international prices. In 2018, the generation installed capacity in the Chilean market was composed of the following:

Installed Capacity	**SEN**
Thermoelectric	54%
Hydroelectric	27%
Solar	10%
Wind	7%
Other	2%

Hydroelectric plants represent a significant portion of the system's installed capacity. Hydrological conditions influence reservoir water levels, which in turn affects dispatch of the system's hydroelectric and thermoelectric generation plants, thereby influencing spot market prices. Precipitation and snow melt impact hydrological conditions in Chile. Rains occurs principally between June and August and are scarce during the remainder of the year. Snow melt occurs between September and November.

The Ministry of Energy has primary responsibility for the Chilean electricity system directly or through the National Energy Commission and the Superintendency of Electricity and Fuels.

In July 2016, modifications to the Transmission Law were enacted. This law establishes that the transmission system will be completely paid for by the end-users, gradually allocating the costs on the demand side from 2019 through 2034.

All generators can sell energy through contracts with regulated distribution companies or directly to unregulated customers. Unregulated customers are customers whose connected capacity is higher than 5 MW. Customers with connected capacity between 0.5 MW and 5.0 MW can opt for regulated or unregulated contracts for a minimum period of four years. By law, both regulated and unregulated customers are required to purchase all electricity under contracts. Generators may also sell energy to other power generation companies on a short-term basis at negotiated prices outside the spot market. Electricity prices in Chile are denominated in U.S. dollars, although payments are made in Chilean pesos.

Business Description — In Chile, through AES Gener, we are engaged in the generation and supply of electricity (energy and capacity) in the SEN. AES Gener is the second largest generation operator in Chile in terms of installed capacity with 3,400 MW, excluding energy storage , and has a market share of approximately 14% as of December 31, 2018.

AES Gener owns a diversified generation portfolio in Chile in terms of geography, technology, customers and fuel source. AES Gener's plants are located near the principal electricity consumption centers, including Santiago, Valparaiso and Antofagasta. AES Gener's diverse generation portfolio provides flexibility for the management of contractual obligations with regulated and unregulated customers, provides backup energy to the spot market and facilitates operations under a variety of market and hydrological conditions.

Our commercial strategy in Chile aims to maximize margin while reducing cash flow volatility. To achieve this, we contract a significant portion of our coal and hydroelectric baseload capacity under long-term agreements with a diversified customer base. Power plants not considered within our baseload capacity (higher variable cost units, mainly diesel) sell energy on the spot market when operating during scarce system supply conditions, such as low hydrology and/or plant outages. In Chile, sales on the spot market are made only to other generation companies who are members of the SEN at the system marginal cost.

AES Gener currently has long-term contracts, with an average remaining term of approximately 11 years, with regulated distribution companies and unregulated customers, such as mining and industrial companies. In general, these long-term contracts include pass-through mechanisms for fuel costs along with price indexations to US CPI.

In addition to energy payments, AES Gener also receives capacity payments to compensate for availability during periods of peak demand. CEN annually determines the capacity requirements for each power plant. The capacity price is fixed semiannually by the National Energy Commission and indexed to the CPI and other relevant indices.

*Environmental Regulatio*n — During 2017 and 2016, the Ministry of Environment under the previous administration updated the Atmospheric Decontamination Plan for the Ventanas and Huasco regions. Under that proposed plan, no significant investments were needed to comply with new requirements at our plants Ventanas and Guacolda. However, the authority under the current administration rejected that proposed plan on December 30, 2017. In December 2018, a new decontamination plan for the Ventanas and Huasco regions was proposed by the authority under the current administration. Currently, the Environmental Ministry expects approval of the new decontamination plan in early March 2019 and we are currently assessing the impact of the new proposed decontamination plan.

Chilean law requires all electricity generators to supply a certain portion of their total contractual obligations with NCREs. Generation companies are able to meet this requirement by building NCRE generation capacity (wind, solar, biomass, geothermal and small hydroelectric technology) or purchasing NCREs from qualified generators. Non-compliance with the NCRE requirements will result in fines. AES Gener currently fulfills the NCRE requirements by utilizing AES Gener's solar and biomass power plants and by purchasing NCREs from other generation companies. At present, AES Gener is in the process of negotiating additional NCRE supply contracts to meet the future requirements.

In September 2014, a new emission tax, or green tax, was enacted effective January 2017. Emissions of PM, SO_2, NO_x and CO_2 are monitored for plants with an installed capacity over 50 MW; these emissions are taxed. In the case of CO_2, the tax will be equivalent to $5 per ton emitted. PPAs originating from the SING have clauses allowing the Company to pass the green tax costs to unregulated customers. Distribution PPAs originating from the SIC do not allow for the pass through of these costs.

Key Financial Drivers — Hedge levels at AES Gener limit volatility to the underlying financial drivers. In addition, financial results are likely to be driven by many factors, including, but not limited to:

- dry hydrology scenarios;
- forced outages;
- changes in current regulatory rulings altering the ability to pass through or recover certain costs;
- fluctuations of the Chilean peso (our hedging strategy reduces this risk, but some residual risk remains);
- tax policy changes;
- legislation promoting renewable energy and/or more restrictive regulations on thermal generation assets; and
- market price risk when re-contracting.

Construction and Development — AES Gener continues to advance the construction of the 531 MW Alto Maipo run-of-the-river hydroelectric plant. Alto Maipo is the largest project in construction in the SEN market. When completed, it will include 75 km of tunnels, two power houses and 17 km of transmission lines. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Alto Maipo.*

Colombia

Regulatory Framework and Market Structure — Electricity supply in Colombia is concentrated in one main system, the SIN, which encompasses one-third of Colombia's territory, providing electricity to 97% of the country's population. The SIN's installed capacity, primarily hydroelectric (68%) and thermal (31%), totaled 17,392 MW as of December 31, 2018. The marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2018, 84% of total energy demand was supplied by hydroelectric plants.

The electricity sector in Colombia operates under a competitive market framework for the generation and sale of electricity, and a regulated framework for transmission and distribution of electricity. The distinct activities of the electricity sector are governed by Colombian laws and the CREG, regulating entity for energy and gas. Other government entities have a role in the electricity industry, including the Ministry of Mines and Energy, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing utility companies; and the Mining and Energetic Planning Unit, which is in charge of expansion of the generation and transmission network.

The generation sector is organized on a competitive basis with companies selling their generation in the wholesale market at the short-term price or under bilateral contracts with other participants, including distribution companies, generators and traders, and unregulated customers at freely negotiated prices. The National Dispatch Center dispatches generators in merit order based on bid offers in order to ensure that demand will be satisfied by the lowest cost combination of available generating units.

In 2018, the Ministry of Mines and Energy published the final resolution for renewable energy auctions in Colombia. The auction allocates 12-year energy contracts for 1.1 TW/h of energy demand under which renewable generators commit to be in commercial operation by December 2021. The auction is scheduled for February 2019 and the regulator expects to adopt the current regulation for the entry of renewable generation to the market during 2019.

Business Description — We operate in Colombia through AES Chivor, a subsidiary of AES Gener, which owns a hydroelectric plant with an installed capacity of 1,000 MW, and Tunjita, a 20 MW run-of-river hydroelectric plant, both located approximately 160 km east of Bogota. AES Chivor’s installed capacity accounted for approximately 6% of system capacity at the end of 2018. AES Chivor is dependent on hydrological conditions, which influence generation and spot prices of non-contracted generation in Colombia.

AES Chivor's commercial strategy aims to execute contracts with commercial and industrial customers, and bid in public tenders for one to four year contracts, mainly with distribution companies to reduce margin volatility with proper portfolio risk management. The remaining energy generated by our portfolio is sold to the spot market, including ancillary services. Additionally, AES Chivor receives reliability payments for maintaining the plant available during periods of power scarcity, such as adverse hydrological conditions, in order to prevent power shortages.

Key Financial Drivers — Hydrological conditions largely influence Chivor's power generation. Maintaining the appropriate contract level, while maximizing revenue through the sale of excess generation, is key to Chivor's results of operations. Hedge levels at Chivor limit volatility in the underlying financial drivers. In addition to hydrology, financial results are driven by many factors, including, but not limited to:

- forced outages;
- fluctuations of the Colombian peso; and
- spot market prices.

Argentina

Regulatory Framework and Market Structure — Argentina has one main power system, the SADI, which serves 96% of the country. As of December 31, 2018, the installed capacity of the SADI totaled 38,538 MW. The SADI's installed capacity is composed primarily of thermoelectric generation (64%) and hydroelectric generation (28%).

Thermoelectric generation in the SADI is primarily natural gas. However, scarcity of natural gas during winter periods (June to August), result in the use of alternative fuels, such as oil and coal. The SADI is also highly reliant on hydroelectric plants. Hydrological conditions impact reservoir water levels and largely influence the dispatch of the system's hydroelectric and thermoelectric generation plants and, therefore, influence market costs. Precipitation in Argentina occurs principally between June and August.

Regulatory Framework — The Argentine regulatory framework divides the electricity sector into generation, transmission and distribution. The wholesale electric market is comprised of generation companies, transmission companies, distribution companies and large customers who are permitted to trade electricity. Generation companies can sell their output in the spot market or under PPAs. CAMMESA manages the electricity market and is responsible for dispatch coordination. The Electricity National Regulatory Agency is in charge of regulating public service activities and the Secretariat of Energy regulates system framework and grants concessions or authorizations for sector activities. In Argentina, the regulator establishes the prices for electricity and fuel and adjusts them periodically for inflation, changes in fuel prices and other factors. As a result, our businesses are particularly sensitive to changes in regulation.

The Argentine electric market is an "average cost" system, with generators being compensated for fixed costs and non-fuel variable costs plus a rate of return. All fuel, except coal, can be provided by CAMMESA. In December 2018, Resolution 70/2018 was enacted. This allows generation companies to buy fuel directly from producers or from CAMMESA.

Argentina’s administration continues introducing regulatory improvements aiming to normalize the energy sector. Among others, Resolution 19/2017 was enacted in 2017 to set higher tariffs, denominated in USD, for energy and capacity prices. The enactment of resolution 19/2017 ceased the remuneration intended to fund increased capacity projects . Likewise, long term USD-denominated PPAs have been awarded to develop 9.4 GW of new capacity (thermal and renewable) through the execution of competitive auctions. During 2018, the government has continued to increase end user prices to reduce subsidies and decrease system deficit.

AES Argentina has contributed certain accounts receivable to fund the construction of new power plants under FONINVEMEM agreements. These receivables accrue interest and are collected in monthly installments over 10 years once the related plants begin to operate. AES Argentina has three FONINVEMEM funds related to operational plants under which payments are being received. AES Argentina will receive a pro rata ownership interest in these plants once the accounts receivables have been fully repaid. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Long-Term Receivables* and Note 6.—*Financing Receivables* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion of receivables in Argentina.

Business Description — As of December 31, 2018, AES operates plants totaling 4,129 MW, representing 11% of the country's total installed capacity. The installed capacity in the SADI includes the TermoAndes plant, a subsidiary of AES Gener, which is connected both to the SADI and the Chilean SEN markets. AES Argentina has a diversified generation portfolio.

AES primarily sells its energy in the wholesale electricity market where prices are largely regulated. In 2018, approximately 93% of the energy was sold in the wholesale electricity market and 7% was sold under contract, as a result of contract sales made by TermoAndes.

Foreign currency controls were lifted in December 2015, allowing the Argentine peso to float under the administration of the Argentinian Central Bank. In 2018, the Argentine peso devalued by approximately 102% and Argentina's economy was determined to be highly inflationary. See Item 7.—*Management's Discussion and Analysis Key Trends and Uncertainties* of this Form 10-K for further discussion.

Tax Regulation — On December 29, 2017, Law 27430 was enacted in Argentina, which introduced a tax reform with several changes in the Argentine tax system, effective on January 1, 2018. This tax reform reduced the statutory corporate tax rate of companies from 35% to 30% in 2018 and 2019, and will reduce the rate to 25% from 2020 onward. The law also eliminated the Equalization Tax on the distribution of earnings generated after January 1, 2018. The Equalization Tax was replaced with a withholding tax on dividends at the rate of 7% for 2018 and 2019, and 13% from 2020 onward.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- forced outages;
- exposure to fluctuations of the Argentine peso;
- changes in hydrology;
- timely collection of FONINVEMEM installment and outstanding receivables (See Note 6.—*Financing Receivables* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further discussion); and
- natural gas prices and availability for contracted generation.

Brazil

Regulatory Framework and Market Structure — In Brazil, the Ministry of Mines and Energy determines the maximum amount of energy a generation plant can sell, called physical guarantee, representing the long-term average expected energy production of the plant. Under current rules, physical guarantee energy can be sold to distribution companies through long-term regulated auctions or under unregulated bilateral contracts with large consumers or energy trading companies.

Brazil has installed capacity of 162,932 MW, which is primarily hydroelectric (64%) and renewables (19%). Operation is centralized and controlled by the national operator, ONS, and regulated by ANEEL. The ONS dispatches generators based on their marginal cost of production and on the risk of system rationing. Key variables for the dispatch decision are forecasted hydrological conditions, reservoir levels, electricity demand, fuel prices and thermal generation availability.

In case of unfavorable hydrology, the ONS will reduce hydroelectric dispatch to preserve reservoir levels and increase dispatch of thermal plants to meet demand. The consequences of unfavorable hydrology are (i) higher energy spot prices due to higher energy production costs by thermal plants and (ii) the need for hydro plants to purchase energy in the spot market to fulfill their contractual obligations.

A mechanism known as the MRE was created under ONS to share hydrological risk across MRE hydro generators. If the hydro plants generate less than the total MRE physical guarantee, the hydro generators may need to purchase energy in the short-term market. When total hydro generation is higher than the total MRE physical guarantee, the surplus is proportionally shared among its participants and they may sell the excess energy on the spot market.

Business Description — Tietê has a portfolio of 12 hydroelectric power plants in the state of São Paulo with total installed capacity of 2,658 MW. Tietê represents approximately 10% of the total generation capacity in the state of São Paulo. Tietê hydroelectric plants operate under a 30-year concession expiring in 2029. AES owns 24% of Tietê and is the controlling shareholder and manages and consolidates this business. Tietê aims to contract most of its physical guarantee requirements and sell the remaining portion in the spot market. The commercial strategy is reassessed periodically according to changes in market conditions, hydrology and other factors. Tietê generally sells available energy through medium-term bilateral contracts.

Tietê's strategy is to grow by adding renewable capacity to its generation platform. In 2017, Tietê acquired Alto Sertão II Wind Complex (“Alto Sertão II”) located in the state of Bahia, with an installed capacity of 386 MW and subject to 20-year PPAs expiring between 2033 and 2035. Furthermore, in 2017 Tiete acquired Boa Hora Solar, a solar development project and won a bid to develop a second solar project, AGV Solar, in the state of São Paulo. In 2018, Tietê acquired Guaimbê, a solar power complex. All the solar assets are fully contracted with 20 year PPAs. Through its ownership of Tietê, AES owns a 24% economic interest in those entities. These assets are not subject to return at the end of the concession.

Under the concession agreement, Tietê is required to increase its capacity in the state of São Paulo by 15% (or 398 MW). The above mentioned investments in new solar generation capacity in the state of São Paulo allowed Tietê to sign a legal agreement in October 2018 with the state government in which it was agreed that: (i) 80% of the expansion obligation (317 MW) was delivered or is in performance stage; and (ii) the Company will have up to six years from the agreement's approval date to meet the remaining balance (81 MW).

Uruguaiana is a 640 MW gas-fired combined cycle power plant located in the town of Uruguaiana in the state of Rio Grande do Sul. AES manages and has a 46% economic interest in the plant. The plant's operations have been largely suspended due to the unavailability of gas. The plant operated for short periods of time in 2013, 2014 and 2015 when short-term supply of LNG was sourced for the facility. The plant did not operate in 2016, 2017 or 2018. AES has evaluated several alternatives to bring gas supply on a competitive basis to Uruguaiana. Capacity restrictions on the Argentinean pipeline are a challenge, especially during the winter season when gas demand in Argentina is very high. Uruguaiana continues to work toward securing gas on a long-term basis.

Key Financial Drivers — As the system is highly dependent on hydroelectric generation, electricity pricing is driven by hydrology in Brazil. Plant availability is also a significant financial driver as in times of high hydrology AES is more exposed to the spot market. The availability of gas is also a driver for continued operations at Uruguaiana. Tietê's financial results are driven by many factors, including, but not limited to:

- hydrology, impacting quantity of energy generated in MRE;
- demand growth;
- re-contracting price;
- asset management and plant availability;
- cost management; and
- ability to execute on its growth strategy.

Construction and Development — As part of the initiative to pursue opportunities in renewable generation discussed above, Tietê is currently constructing photovoltaic power plants with a total projected capacity of 144 MW, subject to 20 year PPAs. Commercial operation of first phase, Boa Hora Solar, and of the second phase, AGV Solar, is expected in the first half of 2019.

MCAC SBU

Our MCAC SBU has a portfolio of generation facilities, including renewable energy, in three countries, with a total capacity of 3,205 MW as of December 31, 2018.

Generation — The following table lists our MCAC SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
DPP (Los Mina)	Dominican Republic	Gas	358	85 %	1996	2022	CDEEE
Andres	Dominican Republic	Gas	319	85 %	2003	2022	Ede Norte/Ede Este/Ede Sur/Non-Regulated Users
Itabo (1)	Dominican Republic	Coal	295	43 %	2000	2022	Ede Norte/Ede Este/Ede Sur
Andres ES	Dominican Republic	Energy Storage	10	85 %	2017		
Los Mina DPP ES	Dominican Republic	Energy Storage	10	85 %	2017		
Dominican Republic Subtotal			**992**				
Merida III	Mexico	Gas	505	75 %	2000	2025	Comision Federal de Electricidad
Termoelectrica del Golfo (TEG)	Mexico	Pet Coke	275	99 %	2007	2027	CEMEX
Termoelectrica del Penoles (TEP)	Mexico	Pet Coke	275	99 %	2007	2027	Penoles
Mexico Subtotal			**1,055**				
Colon (2)	Panama	Gas	381	50 %	2018	2028	Electra Noreste/Edemet/Edechi
Bayano	Panama	Hydro	260	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Changuinola	Panama	Hydro	223	90 %	2011	2030	AES Panama
Chiriqui-Esti	Panama	Hydro	120	49 %	2003	2030	Electra Noreste/Edemet/Edechi/Other
Estrella del Mar I	Panama	Heavy Fuel Oil	72	49 %	2015	2020	Electra Noreste/Edemet/Edechi/Other
Chiriqui-Los Valles	Panama	Hydro	54	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Chiriqui-La Estrella	Panama	Hydro	48	49 %	1999	2030	Electra Noreste/Edemet/Edechi/Other
Panama Subtotal			**1,158**				
			3,205				

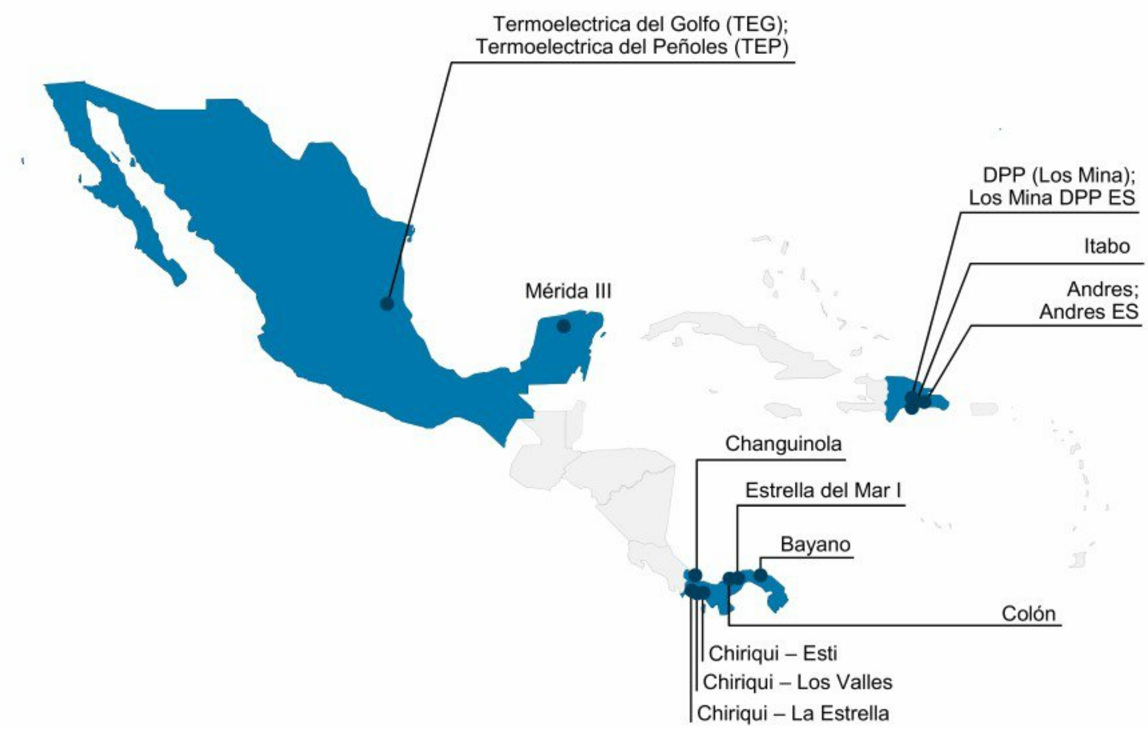
(1) Itabo plants: Itabo complex (two coal-fired steam turbines and one gas-fired steam turbine).
(2) Plant also includes an adjacent regasification facility, as well as a 180,000 m^3 LNG storage tank, which is expected to come on-line in 2019.

Under construction — The following table lists our plants under construction in the MCAC SBU:

Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
Mesa La Paz	Mexico	Wind	306	50%	1H 2020

The following map illustrates the location of our MCAC facilities:

MCAC Businesses



Dominican Republic

Regulatory Framework and Market Structure — The Dominican Republic energy market is a decentralized industry consisting of generation, transmission and distribution businesses. Generation companies can earn revenue through short- and long-term PPAs, ancillary services, and a competitive wholesale generation market. All generation, transmission and distribution companies are subject to and regulated by the General Electricity Law.

Two main agencies are responsible for monitoring compliance with the General Electricity Law:

- The National Energy Commission drafts and coordinates the legal framework and regulatory legislation. They propose and adopt policies and procedures to implement best practices, support the proper functioning and development of the energy sector, and promote investment.
- The Superintendence of Electricity's main responsibilities include monitoring compliance with legal provisions, rules, and technical procedures governing generation, transmission, distribution and commercialization of electricity. They monitor behavior in the electricity market in order to avoid monopolistic practices. In addition to the two agencies responsible for monitoring compliance with the General Electricity Law, the Industrial and Commerce Ministry supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to the end users.

The Dominican Republic has one main interconnected system with approximately 3,800 MW of installed capacity, composed primarily of thermal (78%), hydroelectric (16%), wind (4%) and solar (2%) generation plants/ farms.

Business Description — AES Dominicana consists of three operating subsidiaries, Itabo, Andres and Los Mina. With a total of 992 MW of installed capacity, AES has 26% of the system capacity and supplies approximately 40% of energy demand via these generation facilities. 821 MW is mostly contracted until 2022 with government-owned distribution companies and large customers.

AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), a consortium of two leading Dominican industrial groups that manage a diversified business portfolio.

Itabo is 42.5% owned by AES. Itabo owns and operates two thermal power generation units with a total of 295 MW of installed capacity.

Andres and Los Mina are owned 85% by AES. Andres has a combined cycle natural gas turbine, an energy storage solution and generation capacity of 329 MW as well as the only LNG import facility in the country, with 160,000 cubic meters of storage capacity. Los Mina has a combined cycle with two natural gas turbines, an energy storage solution and generation capacity of 368 MW.

AES Dominicana has a long-term LNG purchase contract through 2023 for 33.6 trillion btu/year with a price linked to NYMEX Henry Hub. The LNG contract terms allow delivery to various markets in Latin America. These plants capitalize on the competitively-priced LNG contract by selling power where the market is dominated by fuel oil-based generation. Andres has a long-term contract to sell re-gasified LNG to industrial users within the Dominican Republic using compression technology to transport it within the country, thereby capturing demand from industrial and commercial customers.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- changes in spot prices due to fluctuations in commodity prices (since fuel is a pass-through cost under the PPAs, any variation in oil prices will impact the spot sales for both Andres and Itabo);
- contracting levels and the extent of capacity awarded;
- supply shortages in the near term (next two to three years) may provide opportunities for short term upside, but new generation is expected to come online beginning 2019; and
- additional sales derived from domestic natural gas demand are expected to continue providing income and growth based on the entry of future projects and the fees from the infrastructure service.

Panama

Regulatory Framework and Market Structure — The Panamanian power sector is composed of three distinct operating business units: generation, distribution and transmission. Generators can enter into long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into alternative supply contracts with each other. Outside of the PPA market, generators may buy and sell energy in the short-term market. Generators can only contract up to their firm capacity.

Three main agencies are responsible for monitoring compliance with the General Electricity Law:

- The SNE has the responsibilities of planning, supervising and controlling policies of the energy sector within Panama. With these responsibilities, the SNE proposes laws and regulations to the executive agencies that regulate the procurement of energy and hydrocarbons for the country.
- The regulator of public services, known as the ASEP, is an autonomous agency of the government. ASEP is responsible for the control and oversight of public services, including electricity, the transmission and distribution of natural gas utilities, and the companies that provide such services.
- The National Dispatch Center implements the economic dispatch of electricity in the wholesale market. The National Dispatch Center's objectives are to minimize the total cost of generation and maintain the reliability and security of the electric power system. Short-term power prices are determined on an hourly basis by the last dispatched generating unit. Physical generation of energy is determined by the National Dispatch Center regardless of contractual arrangements.

Panama's current total installed capacity is 3,501 MW, composed primarily of hydroelectric (49%) and thermal (40%) generation.

Business Description — AES owns and operates five hydroelectric plants and two thermoelectric power plants, Estrella del Mar I and Colon, representing 705 MW and 453 MW of hydro and thermal capacity, respectively and 33% of the total installed capacity in Panama.

The majority of hydroelectric plants in Panama are based on run-of-river technology, with the exception of the 260 MW Bayano plant. Hydrological conditions have an important influence on profitability. Variations in hydrology can result in excess or a shortfall in energy production relative to our contract obligations. Hydro generation is generally in a shortfall position during the dry season from January through May, while thermal assets are expected to be in a long position as their behavior is opposite and complimentary to hydro generation.

Both hydro and thermal assets are mainly contracted through medium- to long-term PPAs with distribution companies. A small volume of contracts are with unregulated users.

Hydro assets in Panama have PPAs with distribution companies up to December 2030 for a total contracted capacity of 350 MW. Thermal assets in Panama have PPAs with distribution companies for a total contracted capacity of 430 MW, of which 80 MW will expire in June 2020 and 350 MW will expire in December 2028.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- changes in hydrology which impacts commodity prices and exposes the business to variability in the cost of replacement power;
- fluctuations in commodity prices, mainly oil and natural gas, affect the cost of thermal generation and spot prices;
- constraints imposed by the capacity of the transmission lines connecting the west side of the country with the load, keeping surplus power trapped during the wet season; and
- country demand as GDP growth is expected to remain strong over the short and medium term.

Construction and Development — In August 2015, AES executed a partnership agreement with Deeplight Corporation, a minority partner, to construct, operate, and maintain a natural gas power generation plant and a liquefied natural gas terminal, in order to purchase and sell energy and capacity as well as commercialize natural gas and other ancillary activities related to natural gas. The combined cycle natural gas power generation plant initiated operations in September 2018 and the liquefied natural gas storage and regasification facility is scheduled for completion in the second half of 2019.

Mexico

Regulatory Framework and Market Structure — Mexico has a single electric grid, the National Electricity System, covering all of Mexico's territory through the Interconnected National Electricity, Baja California and Southern Baja California Systems. The market comprises generation, transmission, distribution and commercialization segments.

Three main agencies, in addition to the Ministry of Energy, are responsible for monitoring compliance with the Electric Industry Law:

- The Energy Regulatory Commission is responsible for the establishment of directives, orders, methodologies and standards oriented to regulate the electric and fuel markets.
- The National Center for Energy Control, as new ISO, is responsible for managing the wholesale electricity market, transmission and distribution infrastructure, planning the network developments, guaranteeing open access to network infrastructure, executing competitive mechanisms to cover regulated demand, and setting transmission charges.
- The CFE owns the transmission and distribution grids and it is also the country's basic supplier. CFE is the offtaker for IPP generators, and together with its own power units has more than 50% of the current generation market share.

Mexico has an installed capacity totaling 74 GW with a generation mix primarily comprising of thermal (71%) and hydroelectric (17%) plants.

Business Description — AES has 1,055 MW of installed capacity in Mexico. The TEG and TEP pet coke-fired plants, located in Tamuin, San Luis Potosi, supply power to their offtakers under long-term PPAs expiring in 2027 with a 90% availability guarantee. TEG and TEP secure their fuel under a long-term contract.

Merida is a CCGT, located in Merida, on Mexico's Yucatan Peninsula. Merida sells power to the CFE under a capacity and energy based long-term PPA through 2025. Additionally, the plant purchases natural gas and diesel under a long-term contract with one of the CFE’s subsidiaries, the cost of which is then passed through to CFE under the terms of the PPA.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- as the companies are fully contracted, improved operational performance provides additional benefits, including performance incentives and/or excess energy sales; and
- changes in the methodology to calculate spot energy prices, which impacts the excess energy sales to CFE.

Construction and Development — AES has partnered in a joint venture with Grupo BAL to co-invest in power and related infrastructure projects in Mexico, focusing on renewable and natural gas generation. The first development, a 306 MW wind project, began construction in 2018 and is expected to be completed in 2020.

Eurasia SBU

Generation — Our Eurasia SBU has generation facilities in six countries. Operating installed capacity totaled 4,578 MW. The following table lists our Eurasia SBU generation facilities:

Business	Location	Fuel	Gross MW	AES Equity Interest	Year Acquired or Began Operation	Contract Expiration Date	Customer(s)
Maritza	Bulgaria	Coal	690	100%	2011	2026	Natsionalna Elektricheska
St. Nikola	Bulgaria	Wind	156	89%	2010	2025	Natsionalna Elektricheska
Bulgaria Subtotal			**846**				
OPGC [1]	India	Coal	420	49%	1998	2026	GRID Corporation Ltd.
Delhi ES	India	Energy Storage	10	60%	2019		
India Subtotal			**430**				
Amman East	Jordan	Gas	381	37%	2009	2033	National Electric Power Company
IPP4	Jordan	Heavy Fuel Oil	250	36%	2014	2039	National Electric Power Company
Jordan Subtotal			**631**				
Netherlands ES	Netherlands	Energy Storage	10	100%	2015		
Netherlands Subtotal			**10**				
Ballylumford [2]	United Kingdom	Gas	708	100%	2010	2023	Power NI/I-SEM
Kilroot [3]	United Kingdom	Coal/Oil	701	99%	1992		I-SEM
Kilroot ES	United Kingdom	Energy Storage	10	100%	2015		
United Kingdom Subtotal			**1,419**				
Mong Duong 2	Vietnam	Coal	1,242	51%	2015	2040	EVN
Vietnam Subtotal			**1,242**				
			4,578				

(1) Unconsolidated entity, the results of operations of which are reflected in Equity in Earnings of Affiliates.
(2) The Ballylumford B Station began the process for a safe shutdown in December 2018.
(3) Includes Kilroot Open Cycle Gas Turbine.

Under construction — The following table lists our plants under construction in the Eurasia SBU:

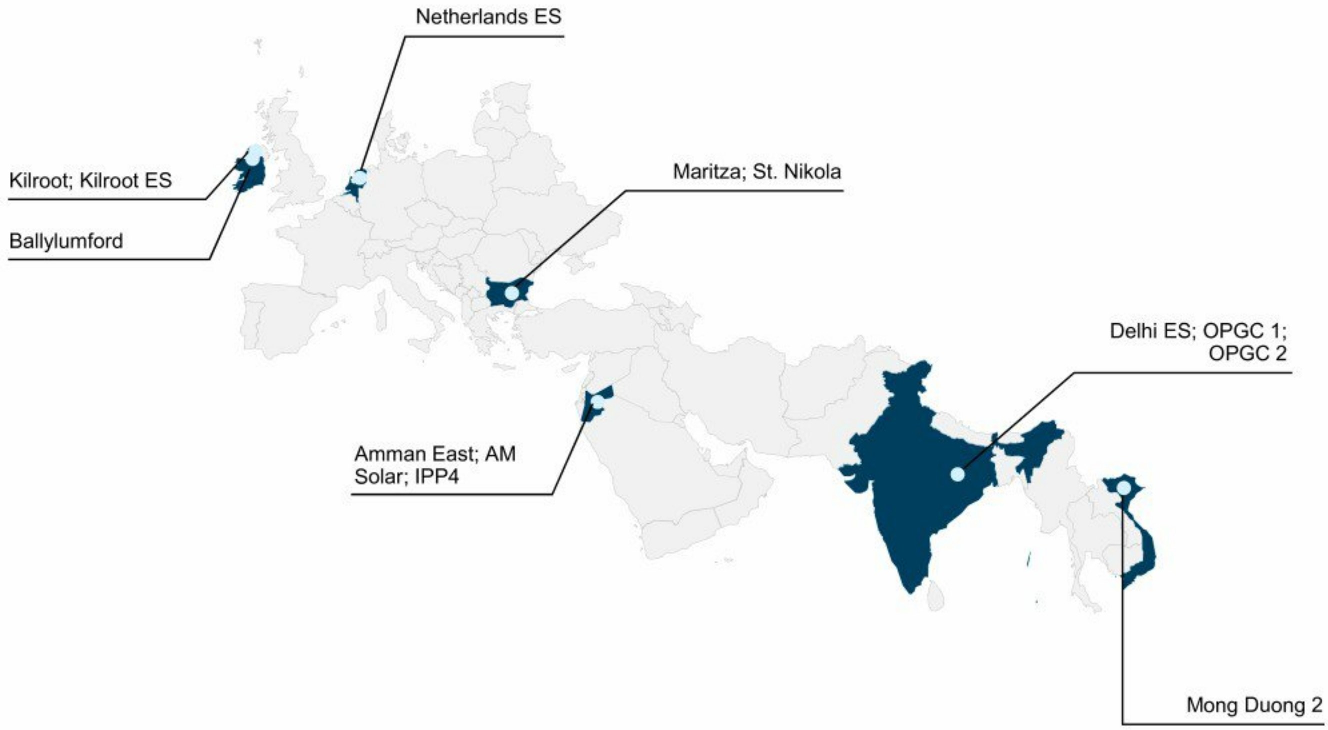
Business	Location	Fuel	Gross MW	AES Equity Interest	Expected Date of Commercial Operations
OPGC 2 [1]	India	Coal	1,320	49 %	1H 2019
AM Solar	Jordan	Solar	52	36 %	2H 2019
			1,372		

(1) Unconsolidated entity, accounted for as an equity affiliate.

In March 2018, the Company completed the sale of its entire 51% ownership interest in Masinloc, a 630 MW coal-fired plant located in the Philippines. Prior to its sale, Masinloc was accounted for as a consolidated entity and its results were included in our operations as we had a controlling interest in the business.

The following map illustrates the location of our Eurasia facilities:

Eurasia Businesses



Bulgaria

Regulatory Framework and Market Structure — The electricity sector in Bulgaria allows both regulated and competitive segments. NEK, the state-owned electricity public supplier and energy trading company, acts as a single buyer and seller for all regulated transactions on the market. Electricity outside the regulated market trades on one of the platforms of the Independent Bulgarian Electricity Exchange day-ahead market, intra-day market or bilateral contracts market. Bulgaria is working with the European Commission on a model that will allow the gradual phase-out of regulated energy prices.

Bulgaria's power sector is supported by a diverse generation mix, universal access to the grid, and numerous cross-border connections in neighboring countries. In addition, it plays an important role in the energy balance in the Balkan region.

Bulgaria has 12 GW of installed capacity enabling the country to meet and exceed domestic demand and export energy. Installed capacity is 37% coal-fired and 17% nuclear.

Business Description — Our Maritza plant is a 690 MW lignite fuel thermal power plant. Maritza's entire power output is contracted with NEK under a 15-year PPA, expiring in May 2026. Since the renegotiation of the PPA in April 2016, Maritza has been collecting receivables from NEK in a timely manner. However, NEK's liquidity position remains subject to political conditions and regulatory changes in Bulgaria.

The DG Comp is reviewing NEK's PPA with Maritza pursuant to the European Commission's state aid rules. Maritza believes that its PPA is legal and in compliance with all applicable laws. See Item 7. —*Management's*

Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Regulatory.

AES also owns an 89% economic interest in the St. Nikola wind farm with 156 MW of installed capacity. Through December 31, 2018, the entire power output of the St. Nikola wind farm was contracted under a 15-year PPA with NEK. Starting January 1, 2019, the power output of St. Nikola is sold on the Independent Bulgarian Electricity Exchange and the plant receives additional revenue per the terms of an October 2018 Contract for Premium with the state-owned Electricity Security Fund.

Environmental Regulation — Best Available Techniques Reference Document for Large Combustion Plants (BREF LCP), the new EU environmental standards regulating emissions from the combustion of solid fuels for large combustion plants, was enacted in August 2017 and applies to Maritza. Impacted power plants are required to either meet the new standards or be granted a derogation by August 2021. Maritza requested such derogation from the Bulgarian environmental authorities in 2018, and expects to receive a response in 2019. If derogation is not received Maritza would seek to pass through the compliance costs to the off-taker pursuant to the PPA.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- regulatory changes to the Bulgaria power market;
- results of the DG Comp review;
- the availability of the operating units;
- the level of wind resources for St. Nikola;
- spot market price volatility beyond the level of compensation through the Contract for Premium for St. Nikola; and
- NEK's ability to meet the payment terms of the PPA contract.

United Kingdom

Regulatory Framework and Market Structure — AES UK operates in the Integrated Single Electricity Market ("I-SEM") in Northern Ireland. The I-SEM is the wholesale electricity market arrangement operating in the Republic of Ireland and Northern Ireland starting October 1, 2018, replacing the previously existing SEM. The I-SEM market arrangements are designed to integrate the Irish All Island electricity market with European electricity markets enabling the free flow of energy across borders, creating increased levels of competition and increased security of supply.

The Single Electricity Market Operator facilitates the continuous operation and administration of the I-SEM. The organization is managed as a contractual joint venture between EirGrid, the transmission system operator for the Republic of Ireland, and the System Operator for Northern Ireland. The Single Electricity Market Operator is licensed and regulated cooperatively by the Commission for Energy Regulation in the Republic of Ireland and the Northern Ireland Authority for Utility Regulation.

In addition, the I-SEM has a competitive capacity payment mechanism to ensure that sufficient generating capacity is offered to the market. The first competitive capacity auction for the capacity year May 2018 to September 2019 was completed in January 2018. The second capacity auction for the capacity year October 2019 to September 2020 was completed on February 1, 2019.

Since the introduction of I-SEM in October 2018, new instruments such as day-ahead, intra-day and balancing markets were introduced to reflect integration with EU energy markets. The system support services market was also reformed in May 2018 through the introduction of DS3, a competitive services market where participants are required to complete a separate qualification process.

Northern Ireland's power sector is supported by a diverse generation mix, a stable regulatory environment, universal access to the grid, and connections between the Republic of Ireland, Northern Ireland and the remainder of the UK. Installed capacity in the I-SEM is 41% gas fired and 38% from renewable sources, resulting in sensitivity to gas prices relative to order of merit. I-SEM has also set a target of 40% renewable generation by 2020.

Business Description — AES has two generation plants in the UK, Kilroot and Ballylumford, both of which are located in Northern Ireland within the Greater Belfast region.

Kilroot is a 701 MW coal-fired merchant plant, with an additional 10 MW of energy storage, that bids into the I-SEM. Kilroot's coal fired units failed to clear in the first I-SEM capacity auction process finalized in January 2018. Consequently, AES announced its intent to shut down the coal units, pending the results of an assessment by the regulator to determine the long term needs of the Northern Ireland power grid. In November 2018, Kilroot's Unit 1 was awarded the 12 month System Support Service Agreement for the period October 2018 to September 2019. In addition, the Company also decided to transfer the capacity contract awarded to Ballylumford Unit 4 to Kilroot Unit 2. As a result, the decision to shut down both Kilroot coal units was reversed.

Ballylumford is a 708 MW gas-fired plant, of which 592 MW is contracted under a PPA with Power NI Power Procurement Business expiring in 2023. The 116 MW remaining capacity is bid into the I-SEM market. Ballylumford's B station Unit 5 failed to clear the aforementioned I-SEM capacity auction while Unit 4’s capacity contract was transferred to Kilroot. As a result, AES stopped generation at Ballylumford's B station in late 2018, and ongoing work to safely shut down the station is expected to be completed in early 2019.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- regulatory changes to the market structure and payment mechanisms;
- investments to maintain compliance with EU environmental legislation;
- weather conditions impacting availability of growing renewables generation;
- availability of the operating units and trading strategy;
- commodity and FX prices (gas, coal, CO2) and sufficient market liquidity to hedge prices in the short-term; and
- electricity demand in the I-SEM (including impact of wind generation).

Jordan

Regulatory Framework and Market Structure — The Jordan electricity transmission market is a single-buyer model with the state owned NEPCO responsible for transmission. NEPCO generally enters into long-term power purchase agreements with IPP's to fulfill energy procurement requests from distribution utilities. The sector is prioritizing renewable energy development, with 2,200 MW of renewable energy installed capacity expected by 2020, 940 MW of which is already connected to the grid.

Business Description — In Jordan, AES has a 37% controlling interest in Amman East, a 381 MW oil/gas-fired plant fully contracted with the national utility under a 25-year PPA expiring in 2033, and a 36% controlling interest in the IPP4 plant, a 250 MW oil/gas-fired peaker plant, fully contracted with the national utility until 2039. We consolidate the results in our operations as we have controlling interest in these businesses.

Construction and Development — AES, in conjunction with Mitsui & Co of Japan and NEBRAS Power of Qatar, have signed an agreement to construct a 52 MW solar project in Jordan. The plant is currently under construction, and is expected to be completed by mid 2019 to coincide with the start of a PPA to provide energy to NEPCO through 2038.

India

Regulatory Framework and Market Structure — The power sector is comprised of state and central government-owned and privately-owned generation and distribution utilities. Electricity is sold to state utilities mostly under long-term PPAs and about 10% of electricity is sold in the short-term market, for example, traded on an energy exchange or through competitively bid bilateral contracts. The tariffs are fixed on yearly basis by the Electricity Regulatory Commissions Central / State(s) for the long-term PPAs or determined through a competitive bidding process. OERC regulates the electricity purchase process for the distribution licensees, including the price at which the electricity from generating companies shall be procured for supply within the state of Orissa. OERC also facilitates intrastate transmission and wheeling of electricity. The electricity regulatory commissions are guided by the Electricity Act, National Electricity Policy, National Electricity Plan and Tariff Policy issued by the Government of India.

The power sector in India is composed of coal, gas, hydroelectric, renewable and nuclear energy. Total installed capacity as of December 31, 2018 was 349 GW, of which 64% is thermal generation. Renewable energy is adding capacity at a rapid pace and currently represents 21% of the total installed capacity. The remaining capacity is nuclear (2%) and hydro (13%).

Business Description — OPGC is a 420 MW coal-fired generation facility located in the state of Odisha. OPGC has a 30-year PPA with GRIDCO Limited, a state utility, expiring in 2026. OPGC is an unconsolidated entity and results are reported as *Net equity in earnings of affiliates* on our Consolidated Statements of Operations.

Construction and Development — AES has one 1,320 MW coal-fired project under construction, which is expected to begin operations in the first half of 2019. As of December 31, 2018, total capitalized costs at the project level were $1.3 billion. Once becoming operational, 75% of the expansion installed capacity is contracted with GRIDCO for a period of four years through 2023 and 100% for the next 25 years through 2048. A separate trading agreement is being negotiated for the remaining 25% of capacity to be sold in the trading market by GRIDCO on behalf of OPGC during the first four years following commencement of operations.

Environmental Regulation — The Ministry of Environment, Forest and Climate Change in India amended the Environment (Protection) Rules with stricter emission limits for thermal power plants through their notification issued in December 2015. All existing plants installed before December 31, 2003 are required to meet revised emission limits within two years and any new thermal power plants that will be operational from January 1, 2017 onwards are required to operate within the revised emission limits. As a result of this amendment, Selective Catalytic Rectifier and Flue Gas Desulphurisation systems are to be installed in the existing OPGC units to comply with the new NO_X and SO_2 emissions limits. The hardware to be installed to meet the tightened emission requirements will require substantial investment by OPGC. We believe the cost of complying with the new environmental regulations for particulate matters, water consumption, SO_x and NO_x limits will be a pass-through in the OERC prescribed tariff regulations for both the existing and expansion units.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to:

- operating performance of the facility;
- regulatory and environmental policy changes;
- tariff determination by the OERC; and
- PPA provisions and energy trading.

Vietnam

Regulatory Framework and Market Structure — The Ministry of Industry and Trade in Vietnam is primarily responsible for formulating a program to restructure the power industry, developing the electricity market, and promulgating electricity market regulations. The fuel supply is owned by the government through Vinacomin, a state-owned entity, and Petro Vietnam.

The Vietnam power market is divided into three regions (North, Central and South), with total installed capacity of approximately 47 GW. The fuel mix in Vietnam is composed primarily of hydropower at 42% and coal at 37%. EVN, the national utility, owns 60% of installed generation capacity.

The government is in the process of realigning EVN-owned companies into three different independent operations in order to create a competitive power market. A competitive electricity market has already been established. A pilot competitive wholesale electricity market has been developed, and will be implemented over the next five years. The retail market will undergo similar reforms after 2022. BOT power plants will not directly participate in the power market; however, their dispatch will be impacted by the merit order

Business Description — Mong Duong II is a 1,242 MW gross coal-fired plant located in Quang Ninh Province of Vietnam and was constructed under a BOT service concession agreement expiring in 2040. This is the first and largest coal-fired BOT plant using pulverized coal-fired boiler technology in Vietnam. The BOT company has a PPA with EVN and a Coal Supply Agreement with Vinacomin both expiring in 2040.

Key Financial Drivers — Financial results are driven by many factors, including, but not limited to, the operating performance and availability of the facility.

Environmental and Land-Use Regulations

The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including existing and potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion residuals), and certain air emissions, such as SO_2, NO_X, PM, mercury and other hazardous air pollutants. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries, and our consolidated results of operations. For further information about these risks, see Item 1A.—*Risk Factors—Our operations are subject to significant government regulation and our business and results of operations could be adversely affected by changes in the law or regulatory schemes; Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR; Our businesses are subject to stringent environmental laws, rules and regulations;* and *Concerns about GHG emissions and the* *potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses* in this Form 10-K. For a discussion of the laws and regulations of individual countries within each SBU where our subsidiaries operate, see discussion within Item 1.—*Business* of this Form 10-K under the applicable SBUs.

Many of the countries in which the Company does business have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from electric power generation or distribution assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced generation technologies in order to minimize environmental impacts, such as combined fluidized bed boilers and advanced gas turbines, and environmental control devices such as flue gas desulphurization for SO_2 emissions and selective catalytic reduction for NO_x emissions.

Environmental laws and regulations affecting electric power generation and distribution facilities are complex, change frequently and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with these environmental laws and regulations. The Company may be required to make significant capital or other expenditures to comply with these regulations. There can be no assurance that the businesses operated by the subsidiaries of the Company will be able to recover any of these compliance costs from their counterparties or customers such that the Company's consolidated results of operations, financial condition and cash flows would not be materially affected.

Various licenses, permits and approvals are required for our operations. Failure to comply with permits or approvals, or with environmental laws, can result in fines, penalties, capital expenditures, interruptions or changes to our operations. Certain subsidiaries of the Company are subject to litigation or regulatory action relating to environmental permits or approvals. See Item 3.— *Legal Proceedings* in this Form 10-K for more detail with respect to environmental litigation and regulatory action.

United States Environmental and Land-Use Legislation and Regulations

In the United States, the CAA and various state laws and regulations regulate emissions of air pollutants, including SO_2, NO_X, PM, GHGs, mercury and other hazardous air pollutants. Certain applicable rules are discussed in further detail below.

CSAPR — CSAPR addresses the "good neighbor" provision of the CAA, which prohibits sources within each state from emitting any air pollutant in an amount which will contribute significantly to any other state's nonattainment, or interference with maintenance of, any NAAQS. The CSAPR required significant reductions in SO_2 and NO_X emissions from power plants in many states in which subsidiaries of the Company operate. The Company is required to comply with the CSAPR in several states, including Ohio, Indiana, Oklahoma and Maryland. The CSAPR is implemented, in part, through a market-based program under which compliance may be achievable through the acquisition and use of emissions allowances created by the EPA. The Company complies with CSAPR through operation of existing controls and purchases of allowances on the open market, as needed.

On October 26, 2016, the EPA published a final rule to update the CSAPR to address the 2008 ozone NAAQS ("CSAPR Update Rule"). The CSAPR Update Rule finds that NO_x ozone season emissions in 22 states (including Indiana, Maryland, Ohio and Oklahoma) affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS, and, accordingly, the EPA issued federal implementation plans that both updated existing CSAPR NO_x ozone season emission budgets for electric generating units within these states and implemented these budgets through modifications to the CSAPR NO_x ozone season allowance trading program. Implementation started in the 2017 ozone season (May-September 2017). Affected facilities began to receive fewer ozone season NO_x allowances in 2017, resulting in the need to purchase additional allowances. While the Company's 2017 and 2018 CSAPR compliance costs were immaterial, the future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time, but it could be material if certain facilities will need to purchase additional allowances based on reduced allocations.

New Source Review ("NSR") — The NSR requirements under the CAA impose certain requirements on major emission sources, such as electric generating stations, if changes are made to the sources that result in a significant increase in air emissions. Certain projects, including power plant modifications, are excluded from these NSR requirements, if they meet the RMRR exclusion of the CAA. There is ongoing uncertainty, and significant litigation, regarding which projects fall within the RMRR exclusion. Over the past several years, the EPA has filed suits against coal-fired power plant owners and issued NOVs to a number of power plant owners alleging NSR violations. See Item 3.—*Legal Proceedings* in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including a NOV issued by the EPA against IPL concerning NSR and prevention of significant deterioration issues under the CAA.

If NSR requirements were imposed on any of the power plants owned by the Company's subsidiaries, the results could have a material adverse impact on the Company's business, financial condition and results of operations.

Regional Haze Rule — The EPA's "Regional Haze Rule" is intended to reduce haze and protect visibility in designated federal areas, and sets guidelines for determining BART at affected plants and how to demonstrate "reasonable progress" toward eliminating man-made haze by 2064. The Regional Haze Rule required states to consider five factors when establishing BART for sources, including the availability of emission controls, the cost of the controls and the effect of reducing emission on visibility in Class I areas (including wilderness areas, national parks and similar areas). The statute would require compliance within five years after the EPA approves the relevant SIP or issues a federal implementation plan, although individual states may impose more stringent compliance schedules. In September 2017, the EPA published a final rule affirming the continued validity of the EPA's previous determination allowing states to rely on the CSAPR to satisfy BART requirements. All of the Company’s facilities that are subject to BART comply by meeting the requirements of CSAPR.

The second phase of the Regional Haze Rule begins in 2019. States must submit regional haze plans for this second implementation period in 2021 to demonstrate reasonable progress towards reducing visibility impairment in Class I areas. States may need to require additional emissions controls for visibility impairing pollutants, including on BART sources, during the second implementation period. We currently cannot predict the impact of this second implementation period, if any, on any of our Company’s U.S. subsidiaries.

National Ambient Air Quality Standards ("NAAQS") — Under the CAA, the EPA sets NAAQS for six principal pollutants considered harmful to public health and the environment, including ozone, particulate matter, NO_x and SO_2, which result from coal combustion. Areas meeting the NAAQS are designated "attainment areas" while those that do not meet the NAAQS are considered "nonattainment areas." Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS, which may include imposing operating limits on individual plants. The EPA is required to review NAAQS at five-year intervals.

Based on the current and potential future ambient air standards, certain of the states in which the Company's subsidiaries operate have determined or will be required to determine whether certain areas within such states meet the NAAQS. Some of these states may be required to modify their State Implementation Plans to detail how the states will attain or maintain their attainment status. As part of this process, it is possible that the applicable state environmental regulatory agency or the EPA may require reductions of emissions from our generating stations to reach attainment status for ozone, fine particulate matter, NO_x or SO_2. The compliance costs of the Company's U.S. subsidiaries could be material.

Beginning January 1, 2017, IPL Petersburg has been required to meet reduced SO_2 limits established in a final rule published by IDEM in 2015 in accordance with a new one-hour SO_2 NAAQS of 75 parts per billion. Improvements to the existing FGD systems at IPL’s Petersburg station were required to meet the emission limits imposed by the rule. The IURC approved IPL’s request for NAAQS SO_2 compliance at its Petersburg generation station with 80% of qualifying costs recovered through a rate adjustment mechanism and the remainder recorded as a regulatory asset for recovery in a subsequent rate case. The approved capital cost of the NAAQS SO_2 compliance plan is approximately $29 million. On August 15, 2018, EPA proposed to approve Indiana’s State Implementation Plan addressing attainment of the 2010 SO_2 standard for certain locations including those of IPL's Petersburg Generating Stations.

Greenhouse Gas Emissions — In January 2011, the EPA began regulating GHG emissions from certain stationary sources, including pre-construction permitting program for certain new construction or major modifications, known as the PSD. If future modifications to our U.S.-based businesses' sources become subject to PSD for other pollutants, it may trigger GHG BACT requirements and the cost of compliance with such requirements may be material.

On October 23, 2015, the EPA's rule establishing NSPS for new electric generating units became effective establishing CO_2 emissions standards for newly constructed coal-fueled electric generating plants, which reflects the partial capture and storage of CO_2 emissions from the plants. The EPA also promulgated NSPS applicable to modified and reconstructed electric generating units, which will serve as a floor for future BACT determinations for such units. The NSPS could have an impact on the Company's plans to construct and/or modify or reconstruct electric generating units in some locations. On December 20, 2018, EPA published proposed revisions to the final NSPS for new, modified and reconstructed coal-fired electric utility steam generating units proposing that the Best System of Emissions Reduction for these units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and sub-critical steam conditions for smaller units, and not partial carbon capture and sequestration, as was finalized in the 2015 final NSPS. EPA did not include revisions for natural-gas combined cycle or simple cycle units in the December 20, 2018 proposal.

On December 22, 2015, the EPA finalized CO_2 emission rules for existing power plants under Clean Air Act Section 111(d) (called the CPP). The CPP provides for interim emissions performance rates that must be achieved beginning in 2022 and final emissions performance rates that must be achieved starting in 2030. The full impact of the CPP would depend on the following:

- whether and how the states in which the Company's U.S. businesses operate respond to the CPP;
- whether the states adopt an emissions trading regime and, if so, which trading regime;
- how other states respond to the CPP, which will affect the size and robustness of any emissions trading market; and
- how other companies may respond in the face of increased carbon costs.

Several states and industry groups challenged the NSPS for CO_2 in the D.C. Circuit. Pursuant to a court order issued in August 2017, the litigation is being held in indefinite abeyance pending further court order.

In addition, on February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of challenges to the rule. Challenges to both the CPP and the GHG NSPS are being held in abeyance at this time. On October 16, 2017, the EPA published in the Federal Register a proposed rule that would rescind the CPP. On December 28, 2017, the EPA published an Advance Notice of Proposed Rulemaking to solicit comments as EPA considers a potential rule to establish emission guidelines to replace the CPP and limit GHG emissions from existing electric generating units under Section 111(d) of the CAA.

On August 31, 2018, the EPA published in the Federal Register proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy (ACE) Rule. In addition, the EPA proposed associated revisions to implementing regulations and the New Source Review program. The proposed ACE Rule would replace the EPA's 2015 Clean Power Plan and proposes to determine that heat rate improvement measures are the best system of emission reduction for existing coal-fired electric generating units.

Due to the future uncertainty of the CPP or potential replacement rule, we cannot at this time determine the impact on our operations or consolidated financial results, but we believe the cost to comply with the CPP, should it be upheld and implemented in its current or a substantially similar form, could be material. The GHG NSPS remains in effect at this time, and, absent further action from the EPA that rescinds or substantively revises the NSPS, it could impact any Company plans to construct and/or modify or reconstruct electric generating units in some locations, which may have a material impact on our business, financial condition or results of operations.

Cooling Water Intake — The Company's facilities are subject to a variety of rules governing water use and discharge. In particular, the Company's U.S. facilities are subject to the CWA Section 316(b) rule issued by the EPA that seeks to protect fish and other aquatic organisms by requiring existing steam electric generating facilities to utilize the BTA for cooling water intake structures. On August 15, 2014, the EPA published its final standards to protect fish and other aquatic organisms drawn into cooling water systems at large power plants. These standards require certain subject facilities to choose among seven BTA options to reduce fish impingement. In addition, facilities that withdraw at least 125 million gallons per day for cooling purposes must conduct studies to assist permitting authorities to determine which site-specific controls, if any, are required to reduce entrainment. It is possible that this decision-making process, which includes permitting and public input, could result in the need to install closed-cycle cooling systems (closed-cycle cooling towers), or other technology. Finally, the standards require that new units added to an existing facility to increase generation capacity are required to reduce both impingement and entrainment. It is not yet possible to predict the total impacts of this recent final rule at this time, including any challenges to such final rule and the outcome of any such challenges. However, if additional capital expenditures are necessary, they could be material.

AES Southland's current plan is to comply with the SWRCB OTC Policy by shutting down and permanently retiring all existing generating units at AES Alamitos, AES Huntington Beach and AES Redondo Beach that utilize OTC by December 31, 2020, the compliance date included in the OTC Policy. New air-cooled combined cycle gas turbine generators and battery energy storage systems will be constructed at the AES Alamitos and AES Huntington Beach generating stations, and there is currently no plan to replace the OTC generating units at the AES Redondo Beach generating station. The execution of the implementation plan for compliance with the SWRCB's OTC Policy is entirely dependent on the Company's ability to execute on long-term power purchase agreements to support project financing of the replacement generating units at AES Alamitos and AES Huntington Beach. The SWRCB is currently reviewing the implementation plan and latest information on OTC generating unit retirement dates and new generation availability to evaluate the impact on electrical system reliability, which could result in the extension of OTC compliance dates for specific units.

The Company's California subsidiaries have signed 20-year term power purchase agreements with Southern California Edison for the new generating capacity which have been approved by the California Public Utilities Commission. Construction of new generating capacity began in June 2017 at AES Huntington Beach and July 2017 at AES Alamitos. Construction at both sites is on schedule and will require the following existing OTC units to retire earlier than December 31, 2020 to provide interconnection capacity and/or emissions credits prior to startup of the new generating units:

- Redondo Beach Unit 7 - September 30, 2019
- Huntington Beach Unit 1 - December 31, 2019
- Alamitos Units 1, 2, and 6 - December 31, 2019

The remaining AES OTC generating units in California will be shutdown and permanently retired by December 31, 2020.

Power plants are required to comply with the more stringent of state or federal requirements. At present, the California state requirements are more stringent and have earlier compliance dates than the federal EPA requirements, and are therefore applicable to the Company's California assets.

Challenges to the federal EPA's rule were filed and consolidated in the U.S. Court of Appeals for the Second Circuit, although implementation of the rule was not stayed while the challenges proceeded. On July 23, 2018, the U.S. Court of Appeals for the Second Circuit upheld the rule. The Second Circuit later denied a petition by environmental groups for rehearing. The Company anticipates that compliance with CWA Section 316(b) regulations and associated costs could have a material impact on our consolidated financial condition or results of operations.

Water Discharges — On June 29, 2015, the EPA and the U.S. Army Corps of Engineers published a final rule defining federal jurisdiction over waters of the United States. This rule, which initially became effective on August 28, 2015, may expand or otherwise change the number and types of waters or features subject to federal permitting. On June 27, 2017, the EPA proposed a rule that would rescind the “Waters of the United States” rule and re-codify the definition of “Waters of the United States” that existed prior to the 2015 rule. However, on February 6, 2018, the EPA published a final rule to delay the original effective date of the 2015 “Waters of the United States” to February 6, 2020, which allows the EPA to create a new rule in the interim period without the 2015 rule taking effect. On June 29, 2018, the agencies signed a supplemental notice of proposed rulemaking clarifying that the proposal is to permanently repeal the 2015 Rule. We cannot predict the outcome of the judicial challenges to the rule or the regulatory process to rescind the rule, but if the “Waters of the United Sates” rule is ultimately implemented in its current or substantially similar form and survives legal challenges, it could have a material impact on our business, financial condition or results of operations. On February 14, 2019, the agencies published a proposed rule to revise the definition of the “Waters of the United States.” We are reviewing the December 11, 2018 proposed rule and it is too early to determine whether this might have a material impact on our business, financial condition or results of operations.

Certain of the Company's U.S.-based businesses are subject to National Pollutant Discharge Elimination System permits that regulate specific industrial waste water and storm water discharges to the waters of the United States under the CWA.

On August 28, 2012, the IDEM issued NPDES permits that set new water quality-based effluent discharge limits for the IPL Harding Street and Petersburg facilities with full compliance ultimately required by September 29, 2017. The deadline for Petersburg to commission a portion of the treatment system was subsequently extended to April 11, 2018.

On November 3, 2015, the EPA published its final ELG rule to reduce toxic pollutants discharged into waters of the U.S. by power plants. These effluent limitations for existing and new sources include dry handling of fly ash, closed-loop or dry handling of bottom ash and more stringent effluent limitations for flue gas de-sulfurization wastewater. The required compliance time lines for existing sources was to be established between November 1, 2018 and December 31, 2023. On September 18, 2017, the EPA published a final rule delaying certain compliance dates of the ELG rule for two years while it administratively reconsiders the rule. IPL Petersburg has installed a dry bottom ash handling system in response to the CCR rule described below and wastewater treatment systems in response to the NPDES permits described above in advance of the ELG compliance date. As a result of the decision to retire Stuart and Killen generating stations, we do not expect the ELG rule to have a material impact on these two stations. While we are still evaluating the effects of the rule on our other U.S. businesses, we anticipate that the implementation of its current requirements could have a material adverse effect on our results of operations, financial condition and cash flows, and a postponement or reconsideration of the rule that leads to less stringent requirements would likely offset some or all of the adverse effects of the rule.

Selenium Rule — In June 2016, the EPA published the final national chronic aquatic life criterion for the pollutant Selenium in fresh water. NPDES permits may be updated to include Selenium water quality based effluent limits based on a site-specific evaluation process which includes determining if there is a reasonable potential to exceed the revised final Selenium water quality standards for the specific receiving water body utilizing actual and/or project discharge information for the generating facilities. As a result, it is not yet possible to predict the total impacts of this final rule at this time, including any challenges to such final rule and the outcome of any such challenges. However, if additional capital expenditures are necessary, they could be material. IPL would seek recovery of these capital expenditures; however, there is no guarantee it would be successful in this regard.

Waste Management — In the course of operations, the Company's facilities generate solid and liquid waste materials requiring eventual disposal or processing. With the exception of coal combustion residuals ("CCR"), the wastes are not usually physically disposed of on our property, but are shipped off site for final disposal, treatment or recycling. CCR, which consists of bottom ash, fly ash and air pollution control wastes, is disposed of at some of our coal-fired power generation plant sites using engineered, permitted landfills. Waste materials generated at our electric power and distribution facilities may include asbestos, CCR, oil, scrap metal, rubbish, small quantities of industrial hazardous wastes such as spent solvents, tree and land clearing wastes and polychlorinated biphenyl contaminated liquids and solids. The Company endeavors to ensure that all of its solid and liquid wastes are disposed of in accordance with applicable national, regional, state and local regulations. On October 19, 2015, an EPA rule regulating CCR under the Resource Conservation and Recovery Act as nonhazardous solid waste became effective. The rule established nationally applicable minimum criteria for the disposal of CCR in new and currently operating landfills and surface impoundments, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements and post-closure care. The primary enforcement mechanisms under this regulation would be actions commenced by the states and private lawsuits. On December 16, 2016, the Water Infrastructure Improvements for the Nation Act ("WIN Act") was signed into law. This includes provisions to implement the CCR rule through a state permitting program, or if the state chooses not to participate, a possible federal permit program. The EPA has indicated that it will implement a phased approach to amending the CCR Rule. It is too early to determine whether the results of the groundwater monitoring data or the outcome of CCR litigation or a potential CCR Remand Rule may have a material impact on our business, financial condition or results of operations.

The existing ash ponds at the Petersburg Station did not meet certain structural stability requirements set forth in the CCR rule. As such, the Company was ultimately required to cease use of all ash ponds at Petersburg by November 11, 2018.

Comprehensive Environmental Response, Compensation and Liability Act of 1980 — This act, also know as "Superfund," may be the source of claims against certain of the Company's U.S. subsidiaries from time to time. There is ongoing litigation at a site known as the South Dayton Landfill where a group of companies already recognized as potentially responsible parties have sued DP&L and other unrelated entities seeking a contribution toward the costs of assessment and remediation. DP&L is actively opposing such claims. In 2003, DP&L received notice that the EPA considers DP&L to be a potentially responsible party at the Tremont City landfill Superfund site. The EPA has taken no further action with respect to DP&L since 2003 regarding the Tremont City landfill. The Company is unable to determine whether there will be any liability, or the size of any liability that may ultimately be assessed against DP&L at these two sites, but any such liability could be material to DP&L.

International Environmental Regulations

For a discussion of the material environmental regulations applicable to the Company's businesses located outside of the U.S., see *Environmental Regulation* under the discussion of the various countries in which the Company's subsidiaries operate in *Business—Our Organization and Segments,* above.

Customers

We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2018 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial and governmental sectors in a defined service area.

Executive Officers

The following individuals are our executive officers:

Sanjeev Addala, 53 years old, was appointed Chief Information and Digital officer in October 2018. Prior to joining AES, Mr. Addala was Chief Digital Officer at GE from 2016 to September 2018, Chief Digital Officer at Caterpillar from 2013 to 2015, and Chief Information Officer, Americas, Climate Control Technologies at Ingersoll-Rand from 2008 to 2013. He also previously held business and technology leadership roles at General Motors from 1994 to 2008. He served on Energize Ventures and AppLariat advisory Boards. Mr. Addala is a member of the Board of AES Distributed Energy. Mr. Addala holds a Master of Science degree in Mechanical Engineering from South Dakota School of Mines and Tech. and a Master of Business Administration degree from the Kellogg School of Management at Northwestern University. Mr. Addala has also completed an Executive Leadership program at Duke University.

***Bernerd Da Santos**,* 55 years old, has been Chief Operating Officer and Executive Vice President since December 2017. Previously, Mr. Da Santos held several positions at the Company, including Chief Operating Officer and Senior Vice President from 2014 to 2017, Chief Financial Officer, Global Finance Operations from 2012 to 2014, Chief Financial Officer of Global Utilities from 2011 to 2012, Chief Financial Officer of Latin America and Africa from 2009 to 2011, Chief Financial Officer of Latin America from 2007 to 2009, Managing Director of Finance for Latin America from 2005 to 2007 and VP and Controller of La Electricidad de Caracas ("EDC") (Venezuela). Prior to joining AES in 2000, Mr. Da Santos held a number of financial leadership positions at EDC. Mr. Da Santos is the chairman of AES Gener in Chile and a member of the Board of Companhia Brasiliana de Energia, AES Tietê, Compañia de Alumbrado Electrico de San Salvador, Empresa Electrica de Oriente, Compañia de Alumbrado Electrico de Santa Ana, and Indianapolis Power & Light. Mr. Da Santos holds a bachelor's degree with Cum Laude distinction in Business Administration and Public Administration from Universidad José Maria Vargas, a bachelor's degree with Cum Laude distinction in Business Management and Finance, and an MBA with Cum Laude distinction from Universidad José Maria Vargas.

Manuel Pérez Dubuc, 55 years old, has served as Senior Vice President, Global New Energy Solutions since October 2018. Previously Mr. Pérez Dubuc served as the President of the South America SBU from March 2018 to October 2018 and President of the MCAC SBU from November 2012 to March 2018. He also served as Vice President and General Manager AES North Asia, President of AES Dominicana and Chief Financial Officer of EDC. Mr. Pérez Dubuc is a member of the Boards of SPower, AES Gener, AES Tiete, Fluence and EnerAB, Ron Santa Teresa SACA and GFR Group Advisory board. Prior to joining AES, Mr. Pérez Dubuc served as a Chairman and CEO of Meiya Power Company based in Hong Kong. Mr. Pérez Dubuc studied electrical engineering at the Universidad Simon Bolivar and with a master’s degree in business administration from IESA (Instituto de Estudios Superiores de Administración) of Caracas, Venezuela. He attended the Executive Leadership Program at the University of Virginia’s Darden School of Business and the Global Executive Leadership Program at Georgetown University’s McDonough School of Business in 2015.

Paul L. Freedman, 48 years old, has been Senior Vice President and General Counsel since February 2018 and was appointed Corporate Secretary in October 2018. Prior to assuming his current position, Mr. Freedman served as Chief of Staff to the Chief Executive Officer from April 2016 to February 2018, Assistant General Counsel from 2014 to 2016, General Counsel, North America Generation, from 2011 to 2014, Senior Corporate Counsel from 2010 to 2011 and Counsel 2007 to 2010. Mr. Freedman is a member of the Boards of IPALCO, AES U.S. Investments, DP&L, Fluence and the Business Council for International Understanding. Prior to joining AES, Mr. Freedman was Chief Counsel for credit programs at the U.S. Agency for International Development and he previously worked as an associate at the law firms of White & Case, LLP and Freshfields. Mr. Freedman received a B.A. from Columbia University and a J.D. from the Georgetown University Law Center.

***Andrés R. Gluski**,* 61 years old, has been President, Chief Executive Officer and a member of our Board of Directors since September 2011 and is a member of the Innovation and Technology Committee. Prior to assuming his current position, Mr. Gluski served as Executive Vice President and Chief Operating Officer of the Company since March 2007. Prior to becoming the Chief Operating Officer of AES, Mr. Gluski was Executive Vice President and the Regional President of Latin America from 2006 to 2007. Mr. Gluski was Senior Vice President for the Caribbean and Central America from 2003 to 2006, Chief Executive Officer of EDC from 2002 to 2003 and Chief Executive Officer of AES Gener (Chile) in 2001. Prior to joining AES in 2000, Mr. Gluski was Executive Vice President and Chief Financial Officer of EDC, Executive Vice President of Banco de Venezuela (Grupo Santander), Vice President for Santander Investment, and Executive Vice President and Chief Financial Officer of CANTV (subsidiary of GTE). Mr. Gluski has also worked with the International Monetary Fund in the Treasury and Latin American Departments and served as Director General of the Ministry of Finance of Venezuela. From 2013 to 2016, Mr. Gluski served on President Obama's Export Council. Mr. Gluski is a member of the Board of Waste

Management and AES Gener in Chile. Mr. Gluski is also Chairman of the Americas Society/Council of the Americas, and Director of the Edison Electric Institute. Mr. Gluski is a magna cum laude graduate of Wake Forest University and holds an M.A. and a Ph.D. in Economics from the University of Virginia.

Lisa Krueger, 55 years old, has served, as Senior Vice President and President of the US SBU since September 2018. Prior to joining AES, Ms. Krueger served as an energy consultant from July 2017 to August 2018, Chief Commercial Officer of Cogentrix Energy Power Management, LLC, the portfolio management company of Carlyle Power Partners, from January 2017 to June 2017, and President and Chief Executive Officer of Essential Power, LLC from March 2014 to June 2017. Ms. Krueger also served as Vice President - Sustainable Development of First Solar, one of the world's largest photovoltaic manufacturers and system integrators, where she led the development and implementation of various domestic and internal strategic plans focused on market and business development and served as the President of First Solar Electric. Prior to First Solar, Ms. Krueger held a variety of executive level positions with Dynegy, Inc., including Vice President - Enterprise Risk Control, Vice President - Northeast Commercial Operations, Vice President - Origination and Retail Operations, and Vice President, Environmental, Health & Safety. She also held a variety of leadership roles at Illinois Power, including positions in transmission planning and system operations, generation planning and system operations, and environmental, health & safety. Ms. Krueger has a Bachelor of Science degree in Chemical Engineering from the Missouri University of Science and Technology and a Master of Business Administration degree from the Jones Graduate School of Business at Rice University.

Tish Mendoza, 43 years old, is Chief Human Resources Officer and Senior Vice President, Global Human Resources and Internal Communications since 2015. Prior to assuming her current position, Ms. Mendoza was the Vice President of Human Resources, Global Utilities from 2011 to 2012 and Vice President of Global Compensation, Benefits and HRIS, including Executive Compensation, from 2008 to 2011 and acted in the same capacity as the Director of the function from 2006 to 2008. In 2015, Ms. Mendoza was appointed a member of the Boards of AES Chivor S.A. and DP&L, and sits on AES' compensation and benefits committees. She is also currently serving as co-chair of Evanta Global HR, and is part of its governing body in Washington, D.C. Prior to joining AES, Ms. Mendoza was Vice President of Human Resources for a product company in the Treasury Services division of JP Morgan Chase and Vice President of Human Resources and Compensation and Benefits at Vastera, Inc, a former technology and managed services company. Ms. Mendoza earned certificates in Leadership and Human Resource Management, and a bachelor's degree in Business Administration and Human Resources.

Leonardo Moreno, 39 years old, has served as Senior Vice President, Corporate Strategy and Investments and Chief Risk Officer since May 2017. Previously Mr. Moreno served as the Chief Financial Officer, Europe SBU from May 2015 to April 2017 and as a Managing Director on AES' Mergers & Acquisitions team from January 2012 to April 2015. Since joining AES in 2006, Mr. Moreno has served in various positions throughout the Company. Mr. Moreno serves as a member of the Board of DP&L and AES Tiete. Prior to joining AES Mr. Moreno worked for Ernst & Young. Mr. Moreno has a degree in Business Administration from Universidade Federal de Minas Gerais, Brazil and has completed executive business and leadership programs at the London Business School, Georgetown University and the University of Virginia.

Julian Nebreda, 52 years old, has served as Senior Vice President and President of the South America SBU since October 2018. Prior to assuming his current position Mr. Nebreda served as the President of the AES Brazil SBU from April 2016 to October 2018, and President of the Europe SBU from June 2009 to April 2016. Prior to June 2009, Mr. Nebreda held several senior positions, such as Vice President for Central America and Caribbean, Chief Executive Officer of EDC and President of AES Dominicana, in Santo Domingo, Dominican Republic. Mr. Nebreda serves as Chairman of the Board of AES Gener and AES Tiete. Before joining AES, Mr. Nebreda has held positions in the public and private sectors, namely he served as Counsellor to the Executive Director from Panama and Venezuela at the Inter-American Development Bank. Mr. Nebreda earned a law degree from Universidad Católica Andrés Bello in Caracas, Venezuela. He also earned a Master of Laws in Common Law with a Fulbright Fellowship and a Master of Laws in Securities and Financial Regulations, both from Georgetown University.

Gustavo Pimenta, 40 years old, was appointed Executive Vice President and Chief Financial Officer effective January 1, 2019. Prior to assuming his current position, Mr. Pimenta served as Deputy Chief Financial Officer from February 2018 to December 2018, Chief Financial Officer for the Company's MCAC SBU from December 2014 to February 2018 and as Chief Financial Officer of AES Brazil from 2013 to December 2014. Prior to joining AES in 2009, Mr. Pimenta held various positions at Citigroup, including Vice President of Strategy and M&A in London and New York City. Mr. Pimenta received a Bachelor's degree in Economics from Universidade Federal de Minas Gerais and a Master's degree in Economics and Finance from Fundação Getulio Vargas. He also participated in development programs in Finance, Strategy and Risk Management at New York University, University of Virginia's Darden School of Business and Georgetown University.

Juan Ignacio Rubiolo, 42 years old, has served Senior Vice President and President of the MCAC SBU since March 2018. Previously Mr. Rubiolo served as the Chief Executive Officer of AES Mexico from 2014 to March 2018 and as a Vice President on the Commercial team of the MCAC SBU from 2013 to 2014. Mr. Rubiolo joined AES in 2001 and has worked in AES businesses in the Philippines, Argentina, Mexico, Panama and the Dominican Republic. Mr. Rubiolo serves on the Boards of AES Gener, Itabo, AES Andres, and AES Panama. Mr. Rubiolo has a Science Degree in Business from the Universidad Austral of Argentina, a Master of Project Management from the Quebec University in Canada and has completed the executive business and leadership program at the University of Virginia.

How to Contact AES and Sources of Other Information

Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is *http://www.aes.com*. Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") are posted on our website. After the reports are filed with, or furnished to the SEC, they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Form 10-K. The SEC maintains an internet website that contains the reports, proxy and information statements and other information that we file electronically with the SEC at *www.sec.gov*.

Our CEO and our CFO have provided certifications to the SEC as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits to this Annual Report on Form 10-K.

Our CEO provided a certification pursuant to Section 303A of the New York Stock Exchange Listed Company Manual on May 8, 2018.

Our Code of Business Conduct ("Code of Conduct") and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern, as a requirement of employment, the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. Our Ethics and Compliance Department provides training, information, and certification programs for AES employees related to the Code of Conduct. The Ethics and Compliance Department also has programs in place to prevent and detect criminal conduct, promote an organizational culture that encourages ethical behavior and a commitment to compliance with the law, and to monitor and enforce AES policies on corruption, bribery, money laundering and associations with terrorists groups. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on our website. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to, or waivers from, the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website.

ITEM 1A. RISK FACTORS

You should consider carefully the following risks, along with the other information contained in or incorporated by reference in this Form 10-K. Additional risks and uncertainties also may adversely affect our business and operations, including those discussed in Item 7.*—Management's Discussion and Analysis of Financial Condition and Results of Operations* in this Form 10-K. If any of the following events actually occur, our business, financial results and financial condition could be materially adversely affected.

We routinely encounter and address risks, some of which may cause our future results to be materially different, than we presently anticipate. The categories of risk we have identified in Item 1A.—*Risk Factors* of this Form 10-K include the following:

- risks related to our indebtedness and financial condition;
- external risks associated with revenue and earnings volatility;
- risks associated with our operations; and
- risks associated with governmental regulation and laws.

These risk factors should be read in conjunction with Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and the Consolidated Financial Statements and related notes included elsewhere in this report.

Risks Related to our Indebtedness and Financial Condition

We have a significant amount of debt, a large percentage of which is secured, that could adversely affect our business and our ability to fulfill our obligations.

As of December 31, 2018, we had approximately $19 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings, if any, under The AES Corporation's senior secured credit facility and secured term loan are secured by certain of our assets, including the pledge of capital stock of many of The AES Corporation's directly held subsidiaries. Most of the debt of The AES Corporation's subsidiaries is secured by substantially all of the assets of those subsidiaries. Since we have such a high level of debt, a substantial portion of cash flow from operations must be used to make payments on this debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral available for future secured debt or credit support and reduces our flexibility in operating these secured assets. This high level of indebtedness and related security could have other important consequences to us and our investors, including:

- making it more difficult to satisfy debt service and other obligations at the holding company and/or individual subsidiaries;
- increasing our vulnerability to general adverse industry and economic conditions, including but not limited to adverse changes in foreign exchange rates, interest rates and commodity prices;
- reducing available cash flow to fund other corporate purposes and grow our business;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry;
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and
- limiting, along with the financial and other restrictive covenants relating to such indebtedness, among other things, our ability to borrow additional funds as needed or take advantage of business opportunities as they arise, pay cash dividends or repurchase common stock.

The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit, but do not prohibit the incurrence of additional indebtedness. If we were to become more leveraged, the risks described above would increase. Further, our actual cash requirements in the future may be greater than expected. Accordingly, our cash flows may not be sufficient to repay at maturity all of the outstanding debt as it becomes due and, in that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms or at all to refinance our debt as it becomes due. In addition, our ability to refinance existing or future indebtedness will depend on the capital markets and our financial condition at such time. Any refinancing of our debt could come at higher interest rates or may require us to comply with onerous covenants, which could restrict our business operations. See Note 10.—*Debt* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for a schedule of our debt maturities.

The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise.

The AES Corporation is a holding company with no material assets other than the stock of its subsidiaries. Almost all of The AES Corporation's cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation's ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, tax sharing payments, loans or otherwise.

However, our subsidiaries face various restrictions in their ability to distribute cash to The AES Corporation. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or non-recourse financing arrangements, to satisfy certain restricted payment covenants or other conditions before they may make distributions to The AES Corporation. Business performance and local accounting and tax rules may also limit dividend distributions. Subsidiaries in foreign countries may also be prevented from distributing funds to The AES Corporation as a result of foreign governments restricting the repatriation of funds or the conversion of currencies.

The AES Corporation's subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed any of The AES Corporation's indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to such debt or to make any funds available whether by dividends, fees, loans or other payments.

Existing and potential future defaults by subsidiaries or affiliates could adversely affect The AES Corporation.

We attempt to finance our domestic and foreign projects primarily under loan agreements and related documents that, except as noted below, require the loans to be repaid solely from the project's revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. This type of financing is usually referred to as non-recourse debt or "non-recourse financing." In some non-recourse financings, The AES Corporation has explicitly agreed to undertake certain limited obligations and contingent liabilities, most of which by their terms will only be effective or will be terminated upon the occurrence of future events. These obligations and liabilities take the form of guarantees, indemnities, letters of credit, letter of credit reimbursement agreements and agreements to pay, in certain circumstances, the project lenders or other parties.

As of December 31, 2018, we had approximately $19.3 billion of outstanding indebtedness on a consolidated basis, of which approximately $3.7 billion was recourse debt of The AES Corporation and approximately $15.6 billion was non-recourse debt. In addition, we have outstanding guarantees, indemnities, letters of credit, and other credit support commitments which are further described in this Form 10-K in Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Parent Company Liquidity*.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our Consolidated Balance Sheets related to such defaults was $351 million as of December 31, 2018. While the lenders under our non-recourse financings generally do not have direct recourse to The AES Corporation (other than to the extent of any credit support given by The AES Corporation), defaults thereunder can still have important consequences for The AES Corporation, including, without limitation:

- reducing The AES Corporation's receipt of subsidiary dividends, fees, interest payments, loans and other sources of cash since the project subsidiary will typically be prohibited from distributing cash to The AES Corporation during the pendency of any default;
- under certain circumstances, triggering The AES Corporation's obligation to make payments under any financial guarantee, letter of credit or other credit support which The AES Corporation may have provided to or on behalf of such subsidiary;
- triggering defaults in The AES Corporation's outstanding debt. For example, The AES Corporation's senior secured credit facility, secured term loan, and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries. In addition, The AES Corporation's senior secured credit facility includes certain events of default relating to accelerations of outstanding material debt of material subsidiaries or any subsidiaries that in the aggregate constitute a material subsidiary; or
- foreclosure on the assets that are pledged under the non-recourse loans, resulting in write-downs of assets and eliminating any and all potential future benefits derived from those assets.

None of the projects that are currently in default are owned by subsidiaries that individually or in the aggregate meet the applicable standard of materiality in The AES Corporation's senior secured credit facility or other debt agreements in order for such defaults to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future mix of distributions, write-down of assets, dispositions and other matters that affect our financial position and results of operations, it is possible that one or more of these subsidiaries, individually or in the aggregate, could fall within the applicable standard of materiality and thereby upon an acceleration of such subsidiary's debt, trigger an event of default and possible acceleration of the indebtedness under The AES Corporation's senior secured credit facility or other indebtedness of The AES Corporation.

The AES Corporation, or the Parent Company, has significant cash requirements and limited sources of liquidity.

The AES Corporation requires cash primarily to fund:

- principal repayments of debt;
- interest;
- acquisitions;
- construction and other project commitments;
- other equity commitments, including business development investments;
- equity repurchases and/or cash dividends on our common stock;
- taxes; and
- Parent Company overhead costs.

The AES Corporation's principal sources of liquidity are:

- dividends and other distributions from its subsidiaries;

- proceeds from debt and equity financings at the Parent Company level; and
- proceeds from asset sales.

For a more detailed discussion of The AES Corporation's cash requirements and sources of liquidity, please see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity* in this Form 10-K.

While we believe that these sources will be adequate to meet our obligations at the Parent Company level for the foreseeable future, this belief is based on a number of material assumptions, which could prove incorrect, including, without limitation, assumptions about our ability to access the capital or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates, our ability to sell assets, and the ability of our subsidiaries to pay dividends and other distributions. There can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. In addition, our cash flow may not be sufficient to repay at maturity the entire principal outstanding under our credit facility, term loan, and our debt securities and we may have to refinance such obligations. There can be no assurance that we will be successful in obtaining such refinancing on terms acceptable to us or at all and any of these events could have a material effect on us.

Our ability to grow our business depends on our ability to raise capital on favorable terms.

From time to time, we rely on access to capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general economic and capital market conditions;
- the availability of bank credit;
- the financial condition, performance and prospects of The AES Corporation in general and/or that of any subsidiary requiring the financing;
- the financial condition, performance and prospects of other companies in our industry or with similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should access to capital not be available to us, we may have to sell assets or decide not to build new plants, or expand or improve existing facilities, either of which would affect our future growth, results of operations or financial condition.

A downgrade in the credit ratings of The AES Corporation or its subsidiaries could adversely affect our access to the capital markets, increase our interest costs and/or adversely affect our liquidity and cash flow.

If any of the credit ratings of The AES Corporation or its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs could increase. Furthermore, depending on The AES Corporation's credit ratings and the trading prices of its equity and debt securities, counterparties may no longer be as willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, with respect to both new and existing commitments, The AES Corporation may be required to provide some other form of assurance, such as a letter of credit and/or collateral, to backstop or replace any credit support by The AES Corporation. There can be no assurance that such counterparties will accept such guarantees or that AES could arrange such further assurances in the future. In addition, to the extent The AES Corporation is required and able to provide letters of credit or other collateral to such counterparties, it will limit the amount of credit available to The AES Corporation to meet its other liquidity needs.

We may not be able to raise sufficient capital to fund development projects in certain less developed economies, which could affect our growth strategy.

Part of our strategy is to grow our business by developing businesses in less developed economies where the return on our investment may be greater than projects in more developed economies. Commercial lending institutions sometimes refuse to provide non-recourse project financing in certain less developed economies, and in these situations we have sought and may continue to seek direct or indirect (through credit support or guarantees) project financing from a limited number of multilateral or bilateral international financial institutions or agencies. As a precondition to making such project financing available, the lending institutions may also require governmental guarantees for certain project and sovereign-related risks. There can be no assurance, however, that project financing from the international financial agencies or that governmental guarantees will be available when needed, and if they are not, we may have to abandon the relevant project or invest more of our own funds, which may not be in line with our investment objectives and would leave less funds for other projects.

External Risks Associated with Revenue and Earnings Volatility

Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets.

Some of our businesses sell electricity in the spot markets when they operate at levels in excess of their power sales agreements or retail load obligations or when they do not have any powers sales agreements. Our businesses may also buy electricity in the wholesale spot markets. As a result, we are exposed to the risks of rising and falling prices in those markets. The open market wholesale prices for electricity can be volatile and generally reflect the variable cost of the source generation which could include renewable sources at near zero pricing or thermal sources subject to fluctuating cost of fuels such as coal, natural gas or oil derivative fuels in addition to other factors described below. Consequently, any changes in the generation supply stack and cost of coal, natural gas, or oil derivative fuels may impact the open market wholesale price of electricity.

Volatility in market prices for fuel and electricity may result from, among other things:

- plant availability in the markets generally;
- availability and effectiveness of transmission facilities owned and operated by third parties;
- competition;
- seasonality;
- hydrology and other weather conditions;
- illiquid markets;
- transmission,transportation constraints, inefficiencies and/or availability;
- renewables source contribution to the supply stack;
- new entrants;
- increased adoption of distributed generation;
- energy efficiency and demand side resources;
- available supplies of coal, natural gas, and crude oil and refined products;
- generating unit performance;
- natural disasters, terrorism, wars, embargoes, and other catastrophic events;
- energy, market and environmental regulation, legislation and policies;
- general economic conditions globally as well as in areas where we operate that impact demand and energy consumption; and
- bidding behavior and market bidding rules.

Adverse economic developments in China could have a negative impact on demand for electricity in many of our markets.

The Chinese market has been driving global materials demand and pricing for commodities over the past decade. Many of these commodities are produced in areas that are also our key markets for the sale of electricity. After experiencing rapid growth for more than a decade, China's economy has experienced decreasing foreign and domestic demand, weak investment, factory overcapacity and oversupply in the property market, and has experienced a significant slowdown in recent years. U.S. tariffs are also expected to have a negative impact on China's economic growth. Continued slowing in China's economic growth, demand for commodities and/or material changes in policy could result in lower economic growth and lower demand for electricity in our key markets, which could have a material adverse effect on our results of operations, financial condition and prospects.

Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations.

Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of the Consolidated Financial Statements, as well as from transaction exposure associated with transactions in currencies other than an entity's functional currency. While the Consolidated Financial Statements are reported in U.S. dollars, the financial statements of several of our subsidiaries outside the United States are prepared using the local currency as the functional currency and translated into U.S. dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. dollar relative to the local currencies where our subsidiaries outside the United States report could cause significant fluctuations in our results. In addition, while our expenses with respect to foreign operations are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not denominated in the subsidiary's functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations. Our financial position and results of operations could be affected by fluctuations in the value of a number of currencies.

Wholesale power prices are declining in many markets and this could have a material adverse effect on our operations and opportunities for future growth.

The wholesale prices offered for electricity have declined significantly in recent years in many markets in which the Company has businesses. This price decline is due to a variety of factors, including the increased penetration of renewable generation resources, low-priced natural gas and demand side management. The levelized cost of electricity from new solar and wind generation sources has dropped substantially in recent years as solar panel costs and wind turbine costs have declined, while wind and solar capacity factors have increased. These renewable resources have no fuel costs and very low operational costs. In many instances, energy from these facilities are bid into the wholesale spot market at a price of zero or close to zero during certain times of the day, driving down the clearing price for all generators selling power in the relevant spot market. Also, in many markets new PPAs have been awarded for renewable generation at prices significantly lower than the prices being awarded just a few years ago.

This trend of declining wholesale prices could continue and could have a material adverse impact on the financial performance of our existing generation assets to the extent they currently sell power into the spot market or will seek to sell power into the spot market once their PPAs expire. The trend of declining prices can also make it more difficult for us to obtain attractive prices under new long-term PPAs for any new generation facilities we may seek to develop. As a result, the trend can have an adverse impact on our opportunities for new investments.

We may not be adequately hedged against our exposure to changes in commodity prices or interest rates.

We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed price or indexed forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. We also enter into contracts which help us manage our interest rate exposure. However, we may not cover the entire exposure of our assets or positions to market price or interest rate volatility, and the coverage will vary over time. Furthermore, the risk management practices we have in place may not always perform as planned. In particular, if prices of commodities or interest rates significantly deviate from historical prices or interest rates or if the price or interest rate volatility or distribution of these changes deviates from historical norms, our risk management practices may not protect us from significant losses. As a result, fluctuating commodity prices or interest rates may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under U.S. GAAP, resulting in increased volatility in our net income. The Company may also suffer losses associated with "basis risk," which is the difference in performance between the hedge instrument and the underlying exposure (usually the pricing node of the generation facility). Furthermore, there is a risk that the current counterparties to these arrangements may fail or are unable to perform part or all of their obligations under these arrangements, while we seek to protect against that by utilizing strong credit requirements and exchange trades, these protections may not fully cover the exposure in the event of a counterparty default.

For our businesses with PPA pricing that does not completely pass through our fuel costs, the businesses attempt to manage the exposure through flexible fuel purchasing and timing of entry and terms of our fuel supply agreements; however, these risk management efforts may not be successful and the resulting commodity exposure could have a material impact on these businesses and/or our results of operations.

Supplier and/or customer concentration may expose the Company to significant financial credit or performance risks.

We often rely on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of some of our facilities. If these suppliers cannot perform, we would seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price, which could adversely impact the profitability of the affected business and our results of operations, and could result in a breach of agreements with other counterparties, including, without limitation, offtakers or lenders.

At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. Counterparties to these agreements may breach or may be unable to perform their obligations, due to bankruptcy, insolvency, financial distress or other factors. Furthermore, in the event of a bankruptcy or similar insolvency-type proceeding, our counterparty can seek to reject our existing PPA under the U.S. Bankruptcy Code or similar bankruptcy laws, including those in Puerto Rico. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, or at all. If we were unable to enter into replacement PPAs, these businesses may have to sell power at market prices. A breach by a counterparty of a PPA or other agreement could also result in the breach of other agreements, including, without limitation, the debt documents of the affected business.

The financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers. Any failure of a supplier or customer to fulfill its contractual obligations to The AES Corporation or our subsidiaries could have a material adverse effect on our financial results.

The market price of our common stock may be volatile.

The market price and trading volumes of our common stock could fluctuate substantially in the future. Factors that could affect the price of our common stock include, among other factors, general conditions in our industry and the power markets in which we participate, environmental and economic developments, and general credit and capital markets conditions, as well as developments specific to us, including risks that could result in revenue and earnings volatility, failing to meet our publicly announced guidance or other risk factors described in Item 1A.—*Risk Factors* and key trends and other matters described in Item 7.—*Management's Discussion and Analysis of Financial Conditions and Results of Operations*.

Risks Associated with our Operations

We do a significant amount of business outside the United States, including in developing countries, which presents significant risks.

A significant amount of our revenue is generated outside the United States and a significant portion of our international operations is conducted in developing countries. Part of our growth strategy is to expand our business in certain developing countries in which AES has an existing presence. We believe these countries may have higher growth rates and offer greater opportunities, with potentially higher returns than in some more developed countries. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws and regulations or in trade, monetary, fiscal or environmental policies;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- unexpected delays in permitting and governmental approvals;
- unexpected changes or instability affecting our strategic partners in developing countries;
- risks relating to the failure to comply with the U.S. Foreign Corrupt Practices Act, UK Bribery Act or other anti-bribery laws applicable to our operations, including, among other things, cost and disruption in responding to allegations or investigations (regardless of ultimate finding), civil and/or criminal fines, criminal prosecution of individuals, revocation or suspension of permits and/or licenses, civil litigation, reputational damage, loss in share price, and loss of business;
- difficulties in hiring, training and retaining qualified personnel, particularly finance and accounting personnel with GAAP expertise;
- unwillingness of governments and their agencies, similar organizations or other counterparties to honor their contracts;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and less beneficial to counterparties, against such counterparties, whether such counterparties are governments or private parties;

- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, by itself or in combination with others, could materially and adversely affect our business, results of operations and financial condition. Our operations may experience volatility in revenues and operating margin which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability and currency devaluations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses. A number of our businesses are facing challenges associated with regulatory changes.

The operation of power generation, distribution and transmission facilities involves significant risks that could adversely affect our financial results.

We are in the business of generating and distributing electricity, which involves certain risks that can adversely affect financial and operating performance, including:

- changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, failure of transmission systems, labor disputes, disruptions in fuel supply, poor hydrologic and wind conditions, inability to comply with regulatory or permit requirements or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, dam failures, tsunamis, explosions, terrorist acts, cyber attacks or other similar occurrences; and
- changes in our operating cost structure, including, but not limited to, increases in costs relating to gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance.

Our businesses require reliable transportation sources (including related infrastructure such as roads, ports and rail), power sources and water sources to access and conduct operations. The availability and cost of this infrastructure affects capital and operating costs and levels of production and sales. Limitations, or interruptions in this infrastructure or at the facilities of our subsidiaries, including as a result of third parties intentionally or unintentionally disrupting this infrastructure or the facilities of our subsidiaries, could impede their ability to produce electricity. This could have a material adverse effect on our businesses' results of operations, financial condition and prospects.

In addition, a portion of our generation facilities were constructed many years ago. Older generating equipment may require significant capital expenditures for maintenance. The equipment at our plants, whether old or new, is also likely to require periodic upgrading, improvement or repair, and replacement equipment or parts may be difficult to obtain in circumstances where we rely on a single supplier or a small number of suppliers. The inability to obtain replacement equipment or parts may impact the ability of our plants to perform and could, therefore, have a material impact on our business and results of operations. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of a power purchase or other agreement or incurrence of a liability for liquidated damages and/or other penalties.

Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquakes, floods, lightning, hurricanes and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or actions of third parties or other external events. The control and management of these risks depend upon adequate development and training of personnel and on the existence of operational procedures, preventative maintenance plans and specific programs supported by quality control systems which reduce, but do not eliminate, the possibility of the occurrence and impact of these risks.

The hazards described above, along with other safety hazards associated with our operations, can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties.

We and/or our subsidiaries may not have adequate risk mitigation and/or insurance coverage for liabilities.

Power generation, distribution and transmission involves hazardous activities. We may from time to time become exposed to significant liabilities for which we may not have adequate risk mitigation and/or insurance coverage. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Our insurance does not cover every potential risk associated with our operations. Adequate coverage at reasonable rates is not always obtainable and due to the cyclical nature of the insurance markets, we cannot provide assurance that insurance coverage will continue to be available on terms similar to those presently available to us or at all. In addition, insurance may not fully cover the liability or the consequences of any business interruptions such as equipment failure or labor dispute.

The occurrence of a significant adverse event not fully or partially covered by insurance could have a material adverse effect on our business, results or operations, financial condition, and prospects.

We may not be able to enter into long-term contracts that reduce volatility in our results of operations.

Many of our generation plants conduct business under long-term sales and supply contracts, which helps these businesses to manage risks by reducing the volatility associated with power and input costs and providing a stable revenue and cost structure. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some cases all of, the relevant plant's output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts of our generation plants range from one to more than 20 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations thereunder, could adversely impact our strategy by resulting in costs that exceed revenue, which could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets, which may not be favorable.

We have sought to reduce counterparty credit risk under our long-term contracts in part by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from certain sovereign governments of the customer's obligations. However, many of our customers do not have, or have failed to maintain, an investment-grade credit rating, and our generation business cannot always obtain government guarantees and if they do, the government does not always have an investment grade credit rating. We have also sought to reduce our credit risk by locating our plants in different geographic areas in order to mitigate the effects of regional economic downturns; however, there can be no assurance that our efforts to mitigate this risk will be successful.

Competition is increasing and could adversely affect us.

The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international) and financial resources similar to, or greater than, ours. Further, in recent years, the power production industry has been characterized by strong and increasing competition with respect to both obtaining power sales agreements and acquiring existing power generation assets. In certain markets, these factors have caused reductions in prices contained in new power sales agreements and, in many cases, have caused higher acquisition prices for existing assets through competitive bidding practices. The evolution of competitive electricity markets and the development of highly efficient gas-fired power plants and renewables such as wind and solar have also caused, and could continue to cause, price pressure in certain power markets where we sell or intend to sell power. In addition, the introduction of low-cost disruptive technologies or the entry of non-traditional competitors into our sector and markets could adversely affect our ability to compete, which could have a material adverse effect on our businesses, operating results and financial condition.

Our businesses will need to continue to adapt to technological change and we may incur significant expenditures to adapt to these changes.

Emerging technologies may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, or may result in the obsolescence of certain of our operating assets. Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services and products that meet customer demands and evolving industry standards.

Technological changes that could impact our businesses include:

- technologies that change the utilization of electric generation, transmission and distribution assets, including the expanded cost-effective utilization of distributed generation (e.g., rooftop solar and community solar projects), and energy storage technology;
- advances in distributed and local power generation and energy storage that reduce the demand for large-scale renewable electricity generation and/or impact our customers' ability to perform under long-term agreements; and
- more cost-effective batteries for energy storage, advances in solar or wind technology, and advances in alternative fuels and other alternative energy sources.

Emerging technologies may also allow new competitors to more effectively compete in our markets or disintermediate the services we provide our customers, including traditional utility and centralized generation services. If we incur significant expenditures in adapting to technological changes, fail to adapt to significant technological changes, fail to obtain access to important new technologies, fail to recover a significant portion of any remaining investment in obsolete assets, or if implemented technology fails to operate as intended, our businesses, operating results and financial condition could be materially adversely affected.

Certain of our businesses are sensitive to variations in weather and hydrology.

Our businesses are affected by variations in general weather patterns and unusually severe weather. Our businesses forecast electric sales based on best available information and expectations for weather, which represents a long-term historical average. While we also consider possible variations in normal weather patterns and potential impacts on our facilities and our businesses, there can be no assurance that such planning can prevent these impacts, which can adversely affect our business. Generally, demand for electricity peaks in winter and summer. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less demand for electricity than forecasted. Significant variations from normal weather where our businesses are located could have a material impact on our results of operations.

Changes in weather can also affect the production of electricity at power generation facilities, including, but not limited to, our wind and solar facilities. For example, the level of wind resource affects the revenue produced by wind generation facilities. Because the levels of wind and solar resources are variable and difficult to predict, our results of operations for individual wind and solar facilities specifically, and our results of operations generally, may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected.
In addition, we are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation.

If hydrological conditions result in droughts or other conditions that negatively affect our hydroelectric generation business, our results of operations could be materially adversely affected. Additionally, our contracts in certain markets where hydroelectric facilities are prevalent may require us to purchase power in the spot markets when our facilities are unable to operate (or operate at lower than anticipated levels) and the price of such spot power may increase substantially in times of low hydrology.

Severe weather and natural disasters may present significant risks to our business and adversely affect our financial results.

Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. In addition, severe weather and natural disasters, such as hurricanes, floods, tornadoes, icing events, earthquakes, dam failures and tsunamis can be destructive and could prevent us from operating our business in the normal course by causing power outages and property damage, reducing revenue, affecting the availability of fuel and water, causing injuries and loss of life, and requiring us to incur additional costs, for example, to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources. Our power plants could be placed at greater risk of damage should changes in the global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, including heatwaves, fewer cold temperature extremes, abnormal levels of precipitation resulting in river and coastal urban floods in North America or reduced water availability and increased flooding across Central and South America, and changes in coast lines due to sea level change.

Depending on the nature and location of the facilities and infrastructure affected, any such incident also could cause catastrophic fires; releases of natural gas, natural gas odorant, or other greenhouse gases; explosions, spills or other significant damage to natural resources or property belonging to third parties; personal injuries, health impacts or fatalities; or present a nuisance to impacted communities. Such incidents that do not directly affect our facilities may impact our business partners, supply chains and transportation, which could negatively impact construction projects and our ability to provide electricity and natural gas to our customers.

A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent us from operating our business in the normal course and could result in any of the adverse consequences described above. At our businesses where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects.

Our development projects are subject to substantial uncertainties.

Certain of our subsidiaries and affiliates are in various stages of developing and constructing power plants. Some but not all of these power plant projects have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion of the development of these projects depends upon overcoming substantial risks, including, but not limited to, risks relating to siting, financing, engineering and construction, permitting, governmental approvals, commissioning delays, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. For additional information regarding our projects under construction see Item 1.—*Business—Our Organization and Segments* included in this Form 10-K.

In certain cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured financing, power purchase arrangements, or other important elements for a successful project. For example, our subsidiaries may instruct contractors to begin the construction process or seek to procure equipment even where they do not have financing, a PPA or critical permits in place (or conversely, to enter into a PPA, procurement agreement or other agreement without financing in place). If the project does not proceed, our subsidiaries may remain obligated for certain liabilities even though the project will not proceed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project. At the time of abandonment, we would expense all capitalized development costs incurred in connection therewith and could incur additional losses associated with any related contingent liabilities.

We do not control certain aspects of our joint ventures.

We have invested in some joint ventures in which our subsidiaries share operational, management, investment and/or other control rights with our joint venture partners. In many cases, we may exert influence over the joint venture pursuant to a management contract, by holding positions on the board of the joint venture company or on management committees and/or through certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of influence over the project or business in every instance and we may be dependent on our joint venture partners or the management team of the joint venture to operate, manage, invest or otherwise control such projects or businesses. Our joint venture partners or the management team of our joint ventures may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities. In some joint venture agreements in which we do have majority control of the voting securities, we have entered into shareholder agreements granting minority rights to the other shareholders.

The approval of joint venture partners also may be required for us to receive distributions of funds from jointly owned entities or to transfer our interest in projects or businesses. The control or influence exerted by our joint venture partners may result in operational management and/or investment decisions that are different from the decisions our subsidiaries would make if they operated independently and could impact the profitability and value of these joint ventures. In addition, in the event that a joint venture partner becomes insolvent or bankrupt or is otherwise unable to meet its obligations to the joint venture or its share of liabilities at the joint venture, we may be subject to joint and several liability for these joint ventures, which means that we may be responsible for meeting certain obligations of the joint ventures, should our joint venture partner be unable to do so, if and to the extent provided for in our governing documents or applicable law.

Our renewable energy projects and other initiatives face considerable uncertainties, including development, operational, and regulatory challenges.

Wind, solar, and energy storage projects are subject to substantial risks. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future.

Furthermore, production levels for our wind and solar projects may be dependent upon adequate wind or sunlight resulting in volatility in production levels and profitability. For example, for our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer. These wind resource estimates are not expected to reflect actual wind energy production in any given year, but long-term averages of a resource.

As a result, these types of renewable energy projects face considerable risk, including the risk that favorable regulatory regimes expire or are adversely modified. In addition, because certain of these projects depend on technology outside of our expertise in generation and utility businesses, there are risks associated with our ability to develop and manage such projects profitably. Furthermore, at the development or acquisition stage, because of our more limited experience with the relevant technologies, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that some of these projects exist in markets where long-term fixed price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility. These projects can be capital-intensive and generally are designed with a view to obtaining third-party financing, which may be difficult to obtain. As a result, these capital constraints may reduce our ability to develop these projects or obtain third-party financing for these projects.

Government incentives and policies that support the development of renewable energy generation projects could change at any time.

AES' U.S. renewable energy generation growth strategy depends in part on federal, state and local government policies and incentives that support the development, financing, ownership and operation of renewable energy generation projects. These policies and incentives include investment tax credits, production tax credits, accelerated depreciation, renewable portfolio standards, feed-in-tariffs and similar programs, renewable energy credit mechanisms, and tax exemptions. If these policies and incentives are changed or eliminated, or AES is unable to use them, it could result in a material adverse impact on AES' U.S. renewable growth opportunities, including fewer future PPAs or lower prices for the sale of power in future PPAs, decreased revenues, reduced economic returns on certain project company investments, increased financing costs, and/or difficulty obtaining financing.

We may not be able to attract and retain skilled people, which could have a material adverse effect on our operations.

Our operating success and ability to carry out growth initiatives depends, in part, on our ability to retain executives and to attract and retain additional qualified personnel who have experience in our industry and in operating a company of our size and complexity, including people in our foreign businesses. The inability to attract and retain qualified personnel could have a material adverse effect on our business, because of the difficulty of promptly finding qualified replacements. For example, we routinely assess the financial impacts of complicated business transactions that occur on a worldwide basis. These assessments are dependent on hiring personnel on a worldwide basis with sufficient expertise in U.S. GAAP to timely and accurately comply with U.S. reporting obligations. An inability to maintain adequate internal accounting and managerial controls and hire and retain qualified personnel could have an adverse effect on our financial and tax reporting.

Cyber-attacks and data security breaches could harm our business.

Our business is heavily reliant on electronic systems and network technologies to operate our generation, transmission and distribution infrastructure. We also use various financial, accounting and other infrastructure systems. Our infrastructure may be targeted by nation states, hacktivists, criminals, insiders or terrorist groups. Such an attack, by hacking, malware or other means, may interrupt our operations, cause property damage, affect our ability to control our infrastructure assets, cause the release of sensitive customer information or limit communications with third parties. Any loss or corruption of confidential or proprietary data through such breach may:

- impair our reputation;
- impact our operations and strategic objectives;
- impact our customer and vendor relationships;
- result in substantial revenue loss;
- expose us to legal claims and/or regulatory investigations and proceedings; and
- require extensive repair and restoration costs for additional security measures to avert future cyber-attacks.

In addition, a breach of our financial and accounting systems could impact our ability to correctly record, process and report financial information.

In addition, in the ordinary course of business, we collect and retain sensitive information, including personal identification information about customers and employees, customer energy usage and other information. The theft, damage or improper disclosure of sensitive electronic data can subject us to penalties for violation of applicable privacy laws, subject us to claims from third parties, require compliance with notification and monitoring regulations, and harm our reputation. The EU GDPR recently came into force and applies to the processing of personal information collected from individuals located in the EU. The GDPR creates new compliance obligations and significantly increases fines for noncompliance.

We have implemented measures to help prevent unauthorized access to our systems and facilities, including certain measures to comply with mandatory regulatory reliability standards. To date, cyber-attacks on our business and operations have not had a material impact on our operations or financial results. We continue to assess potential threats and vulnerabilities and make investments to address them, including global monitoring of networks and systems, identifying and implementing new technology, improving user awareness through employee security training, and updating our security policies as well as those for third-party providers. We cannot guarantee the extent to which our security measures will prevent future cyber-attacks and security breaches or that our insurance coverage will adequately cover any losses we may experience.

Our utilities businesses may be negatively affected by a lack of growth or slower growth in the number of customers or in customer usage.

Customer growth and customer usage in our utilities businesses are affected by a number of factors outside our control, such as mandated energy efficiency measures, demand side management requirements, and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. A lack of growth, or a decline, in the number of customers or in customer demand for electricity may cause us to fail to fully realize the anticipated benefits from significant investments and expenditures and could have a material adverse effect on our growth, business, financial condition, results of operations and prospects.

Some of our subsidiaries participate in defined benefit pension plans and their net pension plan obligations may require additional significant contributions.

We have 30 defined benefit plans, five at U.S. subsidiaries and the remaining plans at foreign subsidiaries, which cover substantially all of the employees at these subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be incorrect, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. We periodically evaluate the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. Our exposure to market volatility is mitigated to some extent due to the fact that the asset allocations in our largest plans include a significant weighting of investments in fixed income securities that are generally less volatile than investments in equity securities. Future downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries' pension plan obligations, could result in an increase in pension expense and future funding requirements, which may be material. Our subsidiaries that participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdictions for any shortfall of pension plan assets as compared to pension obligations under the pension plan. Satisfying such funding requirements may necessitate additional cash contributions to the pension plans that could adversely affect the Parent Company and our subsidiaries' liquidity. For additional information regarding the funding position of the Company's pension plans, see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results* *of Operations—Critical Accounting Policies and Estimates—Pension and Other Postretirement Plans* and Note 13. *—Benefit Plans* included in Item 8.—*Financial Statements and Supplementary Data* included in this Form 10-K.

Impairment of goodwill or long-lived assets would negatively impact our consolidated results of operations and net worth.

As of December 31, 2018, the Company had approximately $1.1 billion of goodwill, which represented approximately 3% of the total assets on its Consolidated Balance Sheets. Goodwill is not amortized, but is evaluated for impairment at least annually, or more frequently if impairment indicators are present. We may be required to evaluate the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to: deterioration in general economic conditions, or our operating or regulatory environment; increased competitive environment; lower forecasted revenue; increase in fuel costs, particularly when we are unable to pass through the impact to customers; increase in environmental compliance costs; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; developments in our strategy; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. For example, during the annual goodwill impairment test performed as of October 1, 2018, the Company determined that the fair value of its Gener reporting unit exceeded its carrying value by 7%. Therefore, Gener's $868 million goodwill balance was considered to be "at risk" for impairment as of December 31, 2018 largely due to the fact that a market participant would no longer assume perpetual cash flows from coal-fired power plants due to the increased penetration of renewable energy in Chile. See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties—Impairments*. These types of events and the resulting analyses could result in goodwill impairment, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if our acquisitions do not perform as expected. See the risk factor *Our acquisitions may not perform as expected* for further discussion.

Long-lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators, similar to those described above for goodwill, are present, whereas goodwill is also evaluated for impairment on an annual basis.

Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, and prospects.

Our acquisitions may not perform as expected.

Historically, acquisitions have been a significant part of our growth strategy. We may continue to grow our business through acquisitions. Although acquired businesses may have significant operating histories, we will have a limited or no history of owning and operating many of these businesses and possibly limited or no experience operating in the country or region where these businesses are located. Some of these businesses may have been government owned and some may be operated as part of a larger integrated utility prior to their acquisition. If we were to acquire any of these types of businesses, there can be no assurance that:

- we will be successful in transitioning them to private ownership;
- such businesses will perform as expected;
- integration or other one-time costs will not be greater than expected;
- we will not incur unforeseen obligations or liabilities;
- such businesses will generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; or
- the rate of return from such businesses will justify our decision to invest capital to acquire them.

Risks associated with Governmental Regulation and Laws

Our operations are subject to significant government regulation and our business and results of operations could be adversely affected by changes in the law or regulatory schemes.

Our ability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any ability to obtain expected or contracted increases in electricity tariff or contract rates or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly at our utilities where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs to be included in the rates we charge our customers, including but not limited to costs incurred to upgrade our power plants to comply with more stringent environmental regulations;
- changes in the determination of what is an appropriate rate of return on invested capital or a determination that a utility's operating income or the rates it charges customers are too high, resulting in a reduction of rates or consumer rebates;
- changes in the definition or determination of controllable or non-controllable costs;
- adverse changes in tax law;
- changes in law or regulation which limit or otherwise affect the ability of our counterparties (including sovereign or private parties) to fulfill their obligations (including payment obligations) to us or our subsidiaries;
- changes in environmental law which impose additional costs or limit the dispatch of our generating facilities within our subsidiaries;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions;
- other changes related to licensing or permitting which affect our ability to conduct business; or
- other changes that impact the short- or long-term price-setting mechanism in the markets where we operate.

Any of the above events may result in lower operating margins for the affected businesses, which can adversely affect our business.

In many countries where we conduct business, the regulatory environment is constantly changing and it may be difficult to predict the impact of the regulations on our businesses. The impacts described above could also result from our (or our subsidiaries') efforts to comply with European Market Infrastructure Regulation, which includes regulations related to the trading, reporting and clearing of derivatives. It is also possible that additional similar regulations may be passed in other jurisdictions where we conduct business. Any of these outcomes could have a material adverse effect on the Company.

Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR.

CCR, which consists of bottom ash, fly ash and air pollution control wastes generated at our current and former coal-fired generation plant sites, is currently handled and/or has been handled in the past in the following ways: placement in onsite CCR ponds; disposal and beneficial use in onsite and offsite permitted, engineered landfills; use in various beneficial use applications, including encapsulated uses and structural fill; and used in permitted offsite mine reclamation. CCR currently remains onsite at several of our facilities, including in CCR ponds. The U.S. EPA's final CCR rule, which became effective in October 2015, regulates CCR as nonhazardous solid waste and establishes national minimum criteria for existing and new CCR landfills and existing and new CCR ponds, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements and post-closure care. On December 16, 2016, President Obama signed the WIN Act into law, which includes provisions to implement the CCR rule through a state permitting program, or if the state chooses not to participate, a possible federal permit program. The primary enforcement mechanisms under this regulation could be actions commenced by U.S. EPA, states, or territories, and private lawsuits. Compliance with the U.S. federal CCR rule; amendments to the federal CCR rule; or federal, state, territory, or foreign rules or programs addressing CCR may require us to incur substantial costs. In addition, the Company and our businesses may face CCR-related lawsuits in the United States and/or internationally that may expose us to unexpected potential liabilities. Furthermore, CCR-related litigation may also expose us to unexpected costs. In addition, CCR, and its production at several of our facilities, have been the subject of significant interest from environmental non-governmental organizations and have received national and local media attention. The direct and indirect effects of such media attention, and the demands of responding to and addressing it, may divert management time and attention. Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects.

Our business in the United States is subject to the provisions of various laws and regulations administered in whole or in part by FERC and NERC, including PURPA, the Federal Power Act, and the EPAct 2005. Actions by FERC, NERC and by state utility commissions can have a material effect on our operations.

The AES Corporation is a registered electric holding company under the 2005 PUHCA as enacted as part of the EPAct 2005. PUHCA 2005 eliminated many of the restrictions that had been in place under the 1935 PUCHA, while continuing to provide FERC and state utility commissions with enhanced access to the books and records of certain utility holding companies. PUHCA 2005 also creates additional potential challenges and opportunities. By removing some barriers to mergers and other potential combinations, the creation of large, geographically dispersed utility holding companies is more likely. These entities may have enhanced financial strength and therefore an increased ability to compete with us in the U.S. market.

Other parts of the EPAct 2005 allow FERC to remove the PURPA purchase/sale obligations from utilities if there are adequate opportunities to sell into competitive markets. FERC has exercised this power with a rebuttable presumption that utilities located within the control areas of MISO, PJM, ISO New England, Inc., the New York Independent System Operator, Inc., and ERCOT are not required to purchase or sell power from or to QFs above a certain size. Additionally, FERC has the power to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While these changes do not affect existing contracts, certain of our QFs that have had sales contracts expire are now facing a more difficult market environment and that is likely to continue for other AES QFs with existing contracts that will expire over time.

In accordance with Congressional mandates in the EPAct 1992 and the EPAct 2005, FERC has strongly encouraged competition in wholesale electric markets. Increased competition may have the effect of lowering our operating margins. Among other steps, FERC has encouraged RTOs and ISOs to develop demand response bidding programs as a mechanism for responding to peak electric demand. These programs may reduce the value of generation assets. Similarly, FERC is encouraging the construction of new transmission infrastructure in accordance with provisions of EPAct 2005. Although new transmission lines may increase market opportunities, they may also increase the competition in our existing markets.

FERC has civil penalty authority over violations of any provision of Part II of the FPA, which concerns wholesale generation or transmission, as well as any rule or order issued thereunder. The FPA also provides for the assessment of criminal fines and imprisonment for violations under the FPA. This penalty authority was enhanced in EPAct 2005. As a result, FERC is authorized to assess a maximum penalty authority established by statute and such penalty authority has been and will continue to be adjusted periodically to account for inflation. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

Pursuant to EPAct 2005, the NERC has been certified by FERC as the Electric Reliability Organization ("ERO") to develop mandatory and enforceable electric system reliability standards applicable throughout the U.S. to improve the overall reliability of the electric grid. These standards are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Violations of NERC reliability standards are subject to FERC's penalty authority under the FPA and EPAct 2005.

Our utility businesses in the U.S. face significant regulation by their respective state utility commissions. The regulatory discretion is reasonably broad in both Indiana and Ohio and includes regulation as to services and facilities, the valuation of property, the construction, purchase, or lease of electric generating facilities, the classification of accounts, rates of depreciation, the increase or decrease in retail rates and charges, the issuance of certain securities, the acquisition and sale of some public utility properties or securities and certain other matters. These businesses face the risk of unexpected or adverse regulatory action which could have a material adverse effect on our results of operations, financial condition, and cash flows. See Item 1.—*Business—US SBU—U.S. Businesses—U.S. Utilities* for further information on the regulation faced by our U.S. utilities.

Our businesses are subject to stringent environmental laws, rules and regulations.

Our businesses are subject to stringent environmental laws and regulations by many federal, regional, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation. Failure to comply with such laws and regulations or to obtain or comply with any associated environmental permits could result in fines or other sanctions. For example, in recent years, the EPA has issued notices of violation (NOVs) to a number of coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against and obtained settlements with many companies for allegedly making major modifications to a coal-fired generating units without proper permit approvals and without installing best available control technology. The primary focus of these NOVs has been emissions of SO_2 and NO_x and the EPA has imposed fines and required companies to install improved pollution control technologies to reduce such emissions. In addition, state regulatory agencies and non-governmental environmental organizations have pursued civil lawsuits against power plants in situations that have resulted in judgments and/or settlements requiring the installation of expensive pollution controls or the accelerated retirement of certain electric generating units.

Furthermore,Congress and other domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air emissions and water discharges. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. See the various descriptions of these laws and regulations contained in Item 1.—*Business—Environmental and Land-Use Regulations* of this Form 10-K.

We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new development of, environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations, would not be materially and adversely affected by such expenditures or any changes in domestic or foreign environmental laws and regulations.

Concerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses.

International, federal and various regional and state authorities regulate GHG emissions and have created financial incentives to reduce them. In 2018, the Company's subsidiaries operated businesses that had total CO_2 emissions of approximately 55 million metric tonnes, approximately 23 million of which were emitted by our U.S. businesses (both figures are ownership adjusted). The Company uses CO_2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO_2 emissions data are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO_2 emission factors. The estimated annual CO_2 emissions from fossil fuel-fired electric power generation facilities of the Company's subsidiaries that are in construction or development and have received the necessary air permits for commercial operations are approximately 7 million metric tonnes (ownership adjusted). This overall estimate is based on a number of projections and assumptions that may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO_2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. However, it is certain that the projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with regulation of GHG emissions. Because there is significant uncertainty regarding these estimates, actual emissions from these projects under construction or development may vary substantially from these estimates.

There currently is no U.S. federal legislation imposing mandatory GHG emission reductions (including for CO_2) that affects our electric power generation facilities; however, in 2015, the EPA promulgated a rule establishing New Source Performance Standards for CO_2 emissions for newly constructed and modified/reconstructed fossil-fueled EUSGUs larger than 25 MW. Also in 2015, the EPA promulgated the Clean Power Plan (CPP), which requires interim reductions by preexisting EUSGUs beginning in 2022, with full compliance achieved by 2030. These actions have been challenged in court and the current Administration has announced plans to significantly amend or rescind the rules. In 2016, the EPA adopted regulations pertaining to GHG emissions that require new and existing sources of GHG emissions to potentially obtain new source review permits from the EPA prior to construction or modification, but only if such sources also must obtain a new source review permit for increases in other regulated pollutants.

For further discussion of the regulation of GHG emissions, including the U.S. Supreme Court's issued order staying implementation of the CPP, and the EPA's proposal to rescind the CPP, see Item 1.—*Business—Environmental and Land-Use Regulations—United States Environmental and Land-Use Legislation and Regulations—Greenhouse Gas Emissions* above.

In December 2015, the Parties to the United Nations Framework Convention on Climate Change convened for the 21st Conference of the Parties and the resulting Paris Agreement established a long-term goal of keeping the increase in global average temperature well below 2°C above pre-industrial levels. We anticipate that the Paris Agreement will continue the trend toward efforts to de-carbonize the global economy and to further limit GHG emissions.

The impact of GHG regulation on our operations will depend on a number of factors, including among others, the degree and timing of GHG emissions reductions required under any such legislation or regulation, the cost of emissions reduction equipment and the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. The costs of compliance could be substantial.

Our non-utility, generation subsidiaries seek to pass on any costs arising from CO_2 emissions to contract counterparties. Likewise, our utility subsidiaries seek to pass on any costs arising from CO_2 emissions to customers. However, there can be no assurance that we will effectively pass such costs onto the contract counterparties or customers, respectively, or that the cost and burden associated with any dispute over which party bears such costs would not be burdensome and costly.

In addition to government regulators, many groups , including politicians, environmentalists, the investor community and other private parties have expressed increasing concern about GHG emissions. Negative public perception of our GHG emissions could have an adverse effect on our relationships with third parties, our ability to attract additional customers or our business development opportunities. In addition, plaintiffs previously brought tort lawsuits against the Company because of its subsidiaries' GHG emissions. While these lawsuits were dismissed, future similar lawsuits may prevail or result in damages awards or other relief. We may also be subject to risks associated with the impact on weather conditions. See Item 1A.—*Risk Factors—Certain of our businesses are sensitive to variations in weather and hydrology* and *Severe weather and natural disasters may present significant risks to our business and adversely affect our financial results for more information*.

If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on our electric power generation businesses and on our consolidated results of operations, financial condition,cash flows and reputation.

Tax legislation initiatives or challenges to our tax positions could adversely affect our results of operations and financial condition.

Our subsidiaries have operations in the U.S. and various non-U.S. jurisdictions. As such, we are subject to the tax laws and regulations of the U.S. federal, state and local governments and of many non-U.S. jurisdictions. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures.

The TCJA enacted December 22, 2017 introduced significant changes to current U.S. federal tax law, including but not limited to lowering the corporate income tax rate, introducing new limits on interest expense deductibility, and changing the way in which foreign earnings are taxed. These changes are complex and are subject to additional guidance to be issued by the U.S. Treasury and the Internal Revenue Service. In addition, the reaction to the federal tax changes by the individual states is evolving. Our interpretations and assumptions around U.S. tax reform may evolve in future periods as further administrative guidance and regulations are issued, which may materially affect our effective tax rate or tax payments. For further details, please see Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Key Trends and Uncertainties* in this Form 10-K.

Additionally, longstanding international tax norms that determine how and where cross-border international trade is subjected to tax are evolving. The Organization for Economic Cooperation and Development, in coordination with the G8 and G20, through its Base Erosion and Profit Shifting project introduced a series of recommendations that many tax jurisdictions have adopted, or may adopt in the future, as law. As these and other tax laws, related regulations and double-tax conventions change, our financial results could be materially impacted. Given the unpredictability of these possible changes and their potential interdependency, it is very difficult to assess whether the overall effect of such potential tax changes would be cumulatively positive or negative for our earnings and cash flow, but such changes could adversely impact our results of operations.

U.S. federal, state and local, as well as non-U.S., tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities and if not sustained, there could be a material impact on our results of operations.

We and our affiliates are subject to material litigation and regulatory proceedings.

We and our affiliates are parties to material litigation and regulatory proceedings. See Item 3.—*Legal Proceedings* below. There can be no assurances that the outcome of such matters will not have a material adverse effect on our consolidated financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We maintain offices in many places around the world, generally pursuant to the provisions of long- and short-term leases, none of which we believe are material. With a few exceptions, our facilities, which are described in Item 1—*Business* of this Form 10-K, are subject to mortgages or other liens or encumbrances as part of the project's related finance facility. In addition, the majority of our facilities are located on land that is leased. However, in a few instances, no accompanying project financing exists for the facility, and in a few of these cases, the land interest may not be subject to any encumbrance and is owned outright by the subsidiary or affiliate.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company has accrued for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company believes, based upon information it currently possesses and taking into account established reserves for estimated liabilities and its insurance coverage, that the ultimate outcome of these proceedings and actions is unlikely to have a material adverse effect on the Company's consolidated financial statements. It is reasonably possible, however, that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material, but that cannot be estimated as of December 31, 2018.

In December 2001, Grid Corporation of Odisha (“GRIDCO”) served a notice to arbitrate pursuant to the Indian Arbitration and Conciliation Act of 1996 on the Company, AES Orissa Distribution Private Limited (“AES ODPL”), and Jyoti Structures (“Jyoti”) pursuant to the terms of the shareholders agreement between GRIDCO, the Company, AES ODPL, Jyoti and the Central Electricity Supply Company of Orissa Ltd. (“CESCO”), an affiliate of the Company. In the arbitration, GRIDCO asserted that a comfort letter issued by the Company in connection with the Company's indirect investment in CESCO obligates the Company to provide additional financial support to cover all of CESCO's financial obligations to GRIDCO. GRIDCO appeared to be seeking approximately $189 million in damages, plus undisclosed penalties and interest, but a detailed alleged damage analysis was not filed by GRIDCO. The Company counterclaimed against GRIDCO for damages. In June 2007, a 2-to-1 majority of the arbitral tribunal rendered its award rejecting GRIDCO's claims and holding that none of the respondents, the Company, AES ODPL, or Jyoti, had any liability to GRIDCO. The respondents' counterclaims were also rejected. A majority of the tribunal later awarded the respondents, including the Company, some of their costs relating to the arbitration. GRIDCO filed challenges of the tribunal's awards with the local Indian court. GRIDCO's challenge of the costs award has been dismissed by the court, but its challenge of the liability award remains pending. A hearing on the liability award has not taken place to date. The Company believes that it has meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

Pursuant to their environmental audit, AES Sul and AES Florestal discovered 200 barrels of solid creosote waste and other contaminants at a pole factory that AES Florestal had been operating. The conclusion of the audit was that a prior operator of the pole factory, Companhia Estadual de Energia (“CEEE”), had been using those contaminants to treat the poles that were manufactured at the factory. On their initiative, AES Sul and AES Florestal communicated with Brazilian authorities and CEEE about the adoption of containment and remediation measures. In March 2008, the State Attorney of the state of Rio Grande do Sul, Brazil filed a public civil action against AES Sul, AES Florestal and CEEE seeking an order requiring the companies to mitigate the contaminated area located on the grounds of the pole factory and an indemnity payment of approximately R$6 million ($2 million). In October 2011, the State Attorney filed a request for an injunction ordering the defendant companies to contain and remove the contamination immediately. The court granted injunctive relief on October 18, 2011, but determined that only CEEE was required to perform the removal work. In May 2012, CEEE began the removal work in compliance with the injunction. The case is now awaiting judgment. The removal costs are estimated to be approximately R$29 million ($8 million), and there could be additional remediation costs which cannot be estimated at this time. In June 2016 the Company sold AES Sul to CPFL Energia S.A. and as part of the sale, AES Guaiba, a holding Company of AES Sul, retained the potential liability relating to this matter. The Company believes that there are meritorious defenses to the claims asserted against it and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2012, the Brazil Federal Tax Authority issued an assessment alleging that AES Tietê had paid PIS and COFINS taxes from 2007 to 2010 at a lower rate than the tax authority believed was applicable. AES Tietê challenged the assessment on the grounds that the tax rate was set in the applicable legislation. In April 2013, the FIAC determined that AES Tietê should have calculated the taxes at the higher rate and that AES Tietê was liable for unpaid taxes, interest, and penalties totaling approximately R$1.21 billion ($312 million) as estimated by AES Tietê. AES Tietê appealed to the SIAC. In January 2015, the Second Instance Administrative Court ("SIAC") issued a decision in AES Tietê's favor, finding that AES Tietê was not liable for unpaid taxes. The public prosecutor subsequently filed an appeal, which was denied as untimely. The Tax Authority thereafter filed a motion for clarification of the SIAC's decision, which was denied in September 2016. The Tax Authority later filed a special appeal ("Special Appeal"), which was rejected as untimely in October 2016. The Tax Authority thereafter filed an interlocutory appeal with the Superior Administrative Court ("SAC"). In March 2017, the President of the SAC determined that the SAC would analyze the Special Appeal. AES Tietê challenged the Special Appeal. In May 2018, the SAC rejected the Special Appeal on the merits. In August 2018, the Tax Authority filed a motion for clarification. AES Tietê believes it has meritorious defenses to the claim and will defend itself vigorously in these proceedings; however, there can be no assurances that it will be successful in its efforts.

In January 2015, DPL received NOVs from the EPA alleging violations of opacity at Stuart and Killen Stations, and in October 2015, IPL received a similar NOV alleging violations at Petersburg Station. In February 2017, the EPA issued a second NOV for DPL Stuart Station, alleging violations of opacity in 2016. Moreover, in February 2016, IPL received an NOV from the EPA alleging violations of NSR and other CAA regulations, the Indiana SIP, and the Title V operating permit at Petersburg Station. It is too early to determine whether the NOVs could have a material impact on our business, financial condition or results of our operations. IPL would seek recovery of any operating or capital expenditures, but not fines or penalties, related to air pollution control technology to reduce regulated air emissions; however, there can be no assurances that we would be successful in this regard.

In September 2015, AES Southland Development, LLC and AES Redondo Beach, LLC filed a lawsuit against the California Coastal Commission (the "CCC") over the CCC's determination that the site of AES Redondo Beach included approximately 5.93 acres of CCC-jurisdictional wetlands. The CCC has asserted that AES Redondo Beach has improperly installed and operated water pumps affecting the alleged wetlands in violation of the California Coastal Act and Redondo Beach Local Coastal Program and has ordered AES Redondo Beach to restore the site. Additional potential outcomes of the CCC determination could include an order requiring AES Redondo Beach to fund a wetland mitigation project and/or pay fines or penalties. AES Redondo Beach believes that it has meritorious arguments and intends to vigorously prosecute such lawsuit, but there can be no assurances that it will be successful.

In October 2015, Ganadera Guerra, S.A. ("GG") and Constructora Tymsa, S.A. ("CT") filed separate lawsuits against AES Panama in the local courts of Panama. The claimants allege that AES Panama profited from a hydropower facility (La Estrella) being partially located on land owned initially by GG and currently by CT, and that AES Panama must pay compensation for its use of the land. The damages sought from AES Panama are approximately $685 million (GG) and $100 million (CT). In October 2016, the court dismissed GG's claim because of GG's failure to comply with a court order requiring GG to disclose certain information. GG has refiled its lawsuit. Also, there are ongoing administrative proceedings concerning whether AES Panama is entitled to acquire an easement over the land and whether AES Panama can continue to occupy the land. AES Panama believes it has meritorious defenses and claims and will assert them vigorously; however, there can be no assurances that it will be successful in its efforts.

In January 2017, the Superintendencia del Medio Ambiente ("SMA") issued a Formulation of Charges asserting that Alto Maipo is in violation of certain conditions of the Environmental Approval Resolution ("RCA") governing the construction of Alto Maipo's hydropower project, for, among other things, operating vehicles at unauthorized times and failing to mitigate the impact of water infiltration during tunnel construction ("Infiltration Water"). In February 2017, Alto Maipo submitted a compliance plan ("Compliance Plan") to the SMA which, if approved by the agency, would resolve the matter without materially impacting construction of the project. Thereafter, the SMA made three separate requests for information about the Compliance Plan, to which Alto Maipo duly responded. In April 2018, the SMA approved the Compliance Plan ("April 2018 Approval"). Among other things the Compliance Plan as approved by the SMA requires Alto Maipo to obtain from the Environmental Evaluation Service ("SEA") an acceptable interpretation of the RCA's provisions concerning the authorized times to operate certain vehicles. In addition, Alto Maipo must obtain the SEA's approval concerning the control, discharge, and treatment of Infiltration Water. Alto Maipo continues to seek the relevant final approvals from the SEA. Furthermore, in May 2018, three lawsuits were filed with the Environmental Court of Santiago ("ECS") challenging the April 2018 Approval. Alto Maipo does not believe that there are grounds to challenge the April 2018 Approval. The ECS has not decided the lawsuits to date. If Alto Maipo complies with the requirements of the Compliance Plan, and if the above-referenced lawsuits are dismissed, the Formulation of Charges will be discharged without penalty. Otherwise, Alto Maipo could be subject to penalties, and the construction of the project could be negatively impacted. Alto Maipo will pursue its interests vigorously in these matters; however, there can be no assurances that it will be successful in its efforts.

In June 2017, Alto Maipo terminated one of its contractors, Constructora Nuevo Maipo S.A. ("CNM"), given CNM's stoppage of tunneling works, its failure to produce a completion plan, and its other breaches of contract. Also, Alto Maipo drew $73 million under letters of credit ("LC Funds") in connection with its termination of CNM. Alto Maipo is pursuing arbitration against CNM to recover excess completion costs and other damages totaling over $230 million (net of the LC Funds) relating to CNM's breaches ("First Arbitration"). CNM denies liability and seeks a declaration that its termination was wrongful, damages, and other relief. CNM has made submissions alleging that it is entitled to damages ranging from $90 million to $150 million (which include the LC Funds) plus interest and costs. Alto Maipo has contested these submissions. There will be another round of briefing. The evidentiary hearing is scheduled for May 20-31, 2019. Also, in August 2018, CNM purported to initiate a separate arbitration against AES Gener and the Company ("Second Arbitration"). In the Second Arbitration, CNM seeks to pierce Alto Maipo's corporate veil and appears to seek an award requiring AES Gener and the Company to pay any amounts that are found to be due to CNM in the First Arbitration or otherwise. Alto Maipo requested in the First Arbitration an interim order restraining CNM from proceeding with the Second Arbitration until the conclusion of the First Arbitration. That request was denied. Separately, AES Gener and the Company requested that the relevant arbitral institution decide that the Second Arbitration shall not proceed, given that (among other reasons) there is no arbitration agreement between AES Gener and the Company and CNM. That request was not granted. Subsequently, AES Gener and the Company requested that the Second Arbitration be consolidated into the First Arbitration. That request was granted. The schedule has not yet been established on CNM's claims against AES Gener and the Company. Each of the above-referenced AES companies believes it has meritorious claims and/or defenses and will pursue its interests vigorously; however, there can be no assurances that each of the AES companies will be successful in its efforts.

In February 2018, Tau Power B.V. and Altai Power LLP (collectively, "AES Claimants") initiated arbitration against the Republic of Kazakhstan ("ROK") for the ROK's failure to pay approximately $75 million ("Return Transfer Payment") for the return of two hydropower plants ("HPPs") pursuant to a concession agreement. In April 2018, the ROK responded by denying liability and asserting purported counterclaims concerning the annual payment provisions in the concession agreement, a bonus allegedly due for the 1997 takeover of the HPPs, and dividends paid by the HPPs. The ROK seeks to recover the Return Transfer Payment (which is in an escrow account maintained by a third party) and appears to be seeking over $480 million on its counterclaims. The AES Claimants believe that the ROK's defenses and counterclaims are without merit. An arbitrator has been appointed to decide the case. The final evidentiary hearing is scheduled for July 22 to 26, 2019. The AES Claimants will pursue their case and assert their defenses vigorously; however, there can be no assurances that they will be successful in their efforts.

In December 2018, a lawsuit was filed in Dominican Republic civil court against the Company, AES Puerto Rico, and three other AES affiliates. The lawsuit purports to be brought on behalf of over 100 Dominican claimants, living and deceased, and appears to seek relief relating to CCRs that were delivered to the Dominican Republic in 2004. The lawsuit generally alleges that the CCRs caused personal injuries and deaths and demands $476 million in alleged damages. The lawsuit does not identify, or provide any supporting information concerning, the alleged injuries of the claimants individually. Nor does the lawsuit provide any information supporting the demand for damages or explaining how the quantum was derived. The relevant AES companies believe that they have meritorious defenses to the claims asserted against them and will defend themselves vigorously in this proceeding; however, there can be no assurances that they will be successful in their efforts.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Stock Repurchase Program — The Board authorization permits the Parent Company to repurchase stock through a variety of methods, including open market repurchases and/or privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The Stock Repurchase Program does not have an expiration date and can be modified or terminated by the Board of Directors at any time. The cumulative repurchase from the commencement of the Stock Repurchase Program in July 2010 through December 31, 2018 is 154.3 million shares at a total cost of $1.9 billion, at an average price per share of $12.12 (including a nominal amount of commissions). As of December 31, 2018, $264 million remained available for repurchase under the Stock Repurchase Program. No repurchases were made by The AES Corporation of its common stock in 2018 and 2017, respectively. The Parent Company repurchased 8,686,983 shares of its common stock in 2016.

Market Information

Our common stock is traded on the New York Stock Exchange under the symbol "AES."

Dividends

The Parent Company commenced a quarterly cash dividend in the fourth quarter of 2012. The Parent Company has increased this dividend annually and the quarterly cash dividend for the last three years are displayed below.

Commencing the fourth quarter of	2018	2017	2016
Cash dividend	$0.1365	$0.13	$0.12

The fourth quarter 2018 cash dividend is to be paid in the first quarter of 2019. There can be no assurance the AES Board will declare a dividend in the future or, if declared, the amount of any dividend. Our ability to pay dividends will also depend on receipt of dividends from our various subsidiaries across our portfolio.

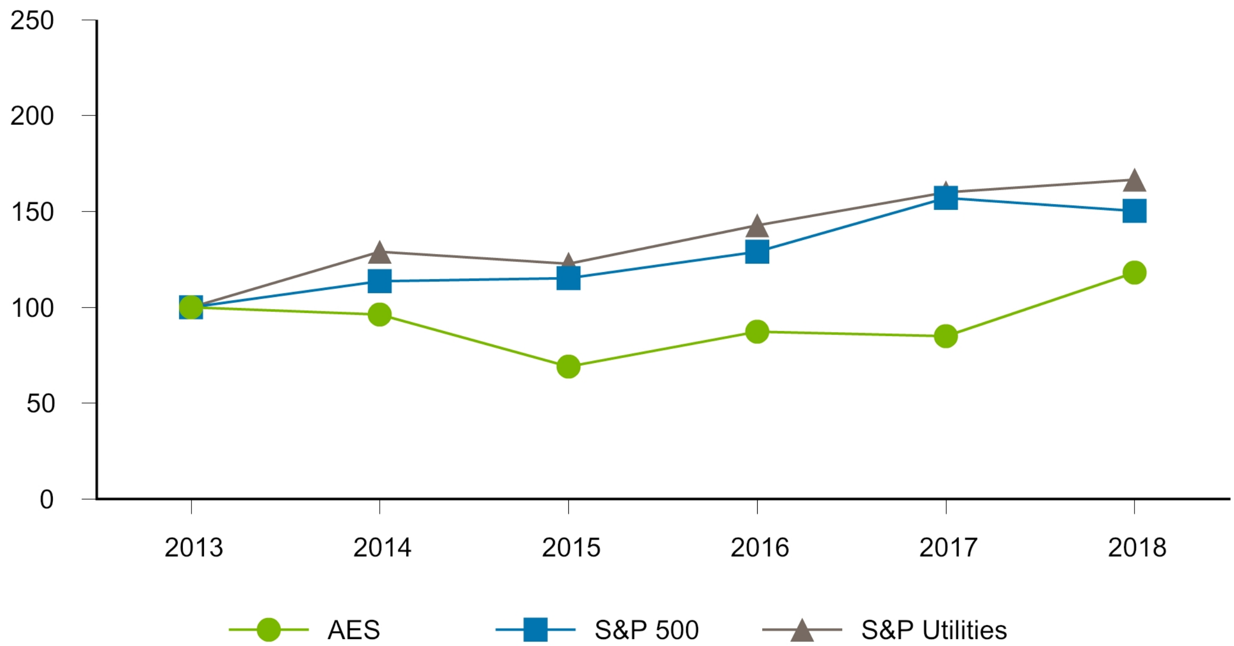
Under the terms of our senior secured credit facility, which we entered into with a commercial bank syndicate, we have limitations on our ability to pay cash dividends and/or repurchase stock. Our subsidiaries' ability to declare and pay cash dividends to us is also subject to certain limitations contained in the project loans, governmental provisions and other agreements to which our subsidiaries are subject. See the information contained under Item 12.—*Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters—Securities Authorized for Issuance under Equity Compensation Plans* of this Form 10-K.

Holders

As of February 21, 2019, there were approximately 3,875 record holders of our common stock.

Performance Graph

THE AES CORPORATION
PEER GROUP INDEX/STOCK PRICE PERFORMANCE



Source: Bloomberg

We have selected the Standard and Poor's ("S&P") 500 Utilities Index as our peer group index. The S&P 500 Utilities Index is a published sector index comprising the 27 electric and gas utilities included in the S&P 500.

The five year total return chart assumes $100 invested on December 31, 2013 in AES Common Stock, the S&P 500 Index and the S&P 500 Utilities Index. The information included under the heading *Performance Graph* shall not be considered "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 or incorporated by reference in any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected financial data as of the dates and for the periods indicated. This data should be read together with Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations* and the Consolidated Financial Statements and the notes thereto included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K. The selected financial data for each of the years in the five year period ended December 31, 2018 have been derived from our audited Consolidated Financial Statements. Prior period amounts have been restated to reflect discontinued operations in all periods presented. Prior to July 1, 2014, a discontinued operation was a component of the Company that either had been disposed of or was classified as held-for-sale and where the Company did not expect to have significant cash flows or significant continuing involvement with the component as of one year after its disposal or sale. Effective July 1, 2014, the Company adopted new accounting guidance under which the Company reports a business as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on the Company's operations and financial results when the business is sold or classified as held-for-sale. Please refer to Note 1—*General and Summary of Significant Accounting Policies* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further explanation. Our historical results are not necessarily indicative of our future results.

Acquisitions, disposals, reclassifications and changes in accounting principles affect the comparability of information included in the tables below. Please refer to the Notes to the Consolidated Financial Statements included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further explanation of the effect of such activities. Please also refer to Item 1A.—*Risk Factors* of this Form 10-K and Note 26—*Risks and Uncertainties* to the Consolidated Financial Statements included in Item 8.—*Financial Statements and*

Supplementary Data of this Form 10-K for certain risks and uncertainties that may cause the data reflected herein not to be indicative of our future financial condition or results of operations.

SELECTED FINANCIAL DATA

	2018	2017	2016	2015	2014
Statement of Operations Data for the Years Ended December 31:	(in millions, except per share amounts)				
Revenue	$ 10,736	$ 10,530	$ 10,281	$ 11,260	$ 12,604
Income (loss) from continuing operations [1]	1,349	(148)	191	682	941
Income (loss) from continuing operations attributable to The AES Corporation, net of tax	985	(507)	(20)	318	678
Income (loss) from discontinued operations attributable to The AES Corporation, net of tax [2]	218	(654)	(1,110)	(12)	91
Net income (loss) attributable to The AES Corporation	$ 1,203	$ (1,161)	$ (1,130)	$ 306	$ 769
Per Common Share Data					
Basic earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.49	$ (0.77)	$ (0.04)	$ 0.46	$ 0.94
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.33	(0.99)	(1.68)	(0.01)	0.13
Net income (loss) attributable to The AES Corporation common stockholders	$ 1.82	$ (1.76)	$ (1.72)	$ 0.45	$ 1.07
Diluted earnings (loss) per share:					
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.48	$ (0.77)	$ (0.04)	$ 0.46	$ 0.94
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.33	(0.99)	(1.68)	(0.02)	0.12
Net income (loss) attributable to The AES Corporation common stockholders	$ 1.81	$ (1.76)	$ (1.72)	$ 0.44	$ 1.06
Dividends Declared Per Common Share	$ 0.53	$ 0.49	$ 0.45	$ 0.41	$ 0.25
Cash Flow Data for the Years Ended December 31:					
Net cash provided by operating activities	$ 2,343	$ 2,504	$ 2,897	$ 2,136	$ 1,800
Net cash used in investing activities	(505)	(2,599)	(2,136)	(2,128)	(1,075)
Net cash provided by (used in) financing activities	(1,643)	43	(747)	28	(1,262)
Total increase (decrease) in cash, cash equivalents and restricted cash	215	(172)	9	(10)	(529)
Cash, cash equivalents and restricted cash, ending	2,003	1,788	1,960	1,951	1,961
Balance Sheet Data at December 31:					
Total assets	$ 32,521	$ 33,112	$ 36,124	$ 36,545	$ 38,676
Non-recourse debt (noncurrent)	13,986	13,176	13,731	12,184	12,077
Non-recourse debt (noncurrent)—Discontinued operations	—	—	758	772	1,226
Recourse debt (noncurrent)	3,650	4,625	4,671	4,966	5,047
Redeemable stock of subsidiaries	879	837	782	538	78
Retained earnings (accumulated deficit)	(1,005)	(2,276)	(1,146)	143	512
The AES Corporation stockholders' equity	3,208	2,465	2,794	3,149	4,272

(1) Includes pre-tax gains on sales of business interests of $984 million, $29 million, $29 million and $358 million for the years ended December 31, 2018, 2016, 2015 and 2014, respectively, and pre-tax losses of $52 million for the year ended December 31, 2017; pre-tax impairment expense of $208 million, $537 million, $1.1 billion, $602 million and $383 million for the years ended December 31, 2018, 2017, 2016, 2015 and 2014, respectively; other-than-temporary impairments of equity method investments of $147 million and $128 million for the years ended December 31, 2018 and 2014, respectively; income tax expense of $194 million and $675 million related to the one-time transition tax on foreign earnings, and income tax benefit of $77 million and expense of $39 million related to the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate for the years ended December 31, 2018 and 2017, respectively. See Note 23—*Held-for-Sale and Dispositions,* Note 8—*Goodwill and Other Intangible Assets*, Note 20—*Asset Impairment Expense,* Note 7—*Investments in and Advances to Affiliates* and Note 21—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

(2) Includes gain on sale of $199 million and loss on deconsolidation of $611 million related to Eletropaulo for the years ended December 31, 2018 and 2017, respectively, and impairment expense of $382 million and loss on sale of $737 million related to Sul for the year ended December 31, 2016. See Note 22—*Discontinued Operations* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Summary

In 2018, AES delivered strong financial results and achieved significant milestones on its strategic goals, including continuing to enhance the resilience of the portfolio and growing the backlog of renewable projects. The Company achieved a key investment grade metric, completed construction of 1.3 GW of new projects and signed long-term PPAs for 2 GW of renewable capacity. See *Overview of our Strategy* included in Item 1.—*Business* of this Form 10-K for further information.

During 2018, the Company saw increased margins at its South America, MCAC and US and Utilities SBUs. These increases were primarily due to higher tariffs and rates in Argentina and the U.S., higher contract prices in Colombia, new PPAs in Chile, and increased sales due to the commencement of operations at the Colon combined cycle facility in Panama and Eagle Valley CCGT in the U.S. The Company also experienced decreased margins in the Eurasia SBU due to completed sales of Masinloc in 2018 and the Kazakhstan facilities in 2017. In addition, the Company reduced its recourse debt by approximately $1 billion in 2018, resulting in a decrease in Parent Company interest.

Overview of 2018 Results

Earnings Per Share Results in 2018 (in millions, except per share amounts)

Years Ended December 31,	**2018**	**2017**	**2016**
Diluted earnings (loss) per share from continuing operations	$ 1.48	$ (0.77)	$ (0.04)
Adjusted EPS (a non-GAAP measure) [1]	1.24	1.08	0.94

(1) See reconciliation and definition under *SBU Performance Analysis—Non-GAAP Measures*.

Diluted earnings per share from continuing operations increased $2.25 to $1.48 for the year ended December 31, 2018, as compared to a loss of $0.77 for the year ended December 31, 2017. This increase was primarily due to the current year gains on sales of Masinloc, CTNG and Electrica Santiago, prior year loss on sale of the Kazakhstan CHPs and HPPs, prior year impairments at DPL, Laurel Mountain and in Kazakhstan, lower interest expense at the Parent Company and Gener, a one-time transition tax on foreign earnings following the enactment of the TCJA in the prior year, and higher margins. These increases were partially offset by higher current year tax expense due to the new GILTI rules in the U.S. in large part due to the sale of our interest in Masinloc, the current year impairment at Shady Point, other-than-temporary impairment of the Guacolda equity method investment in Chile, foreign exchange losses mainly due to the devaluation of the Argentine peso and foreign currency gains in the prior year, higher current year losses on extinguishment of debt, and a favorable legal settlement at Uruguaiana in the prior year.

Adjusted EPS, a non-GAAP measure, increased $0.16, or 15%, to $1.24, reflecting higher margins at the South America, US and Utilities and MCAC SBUs and lower interest on Parent Company debt. These increases were partially offset by lower margin at the Eurasia SBU mainly driven by the sales of Masinloc and Kazakhstan.

Review of Consolidated Results of Operations

Years Ended December 31, (in millions, except per share amounts)	2018	2017	2016	% Change 2018 vs. 2017	% Change 2017 vs. 2016
Revenue:					
US and Utilities SBU	$ 4,230	$ 4,162	$ 4,330	2%	-4%
South America SBU	3,533	3,252	2,956	9%	10%
MCAC SBU	1,728	1,519	1,274	14%	19%
Eurasia SBU	1,255	1,590	1,670	-21%	-5%
Corporate and Other	41	35	77	17%	-55%
Eliminations	(51)	(28)	(26)	-82%	-8%
Total Revenue	10,736	10,530	10,281	2%	2%
Operating Margin:					
US and Utilities SBU	733	693	719	6%	-4%
South America SBU	1,017	862	823	18%	5%
MCAC SBU	534	465	390	15%	19%
Eurasia SBU	227	422	427	-46%	-1%
Corporate and Other	58	23	14	NM	64%
Eliminations	4	—	10	NM	-100%
Total Operating Margin	2,573	2,465	2,383	4%	3%
General and administrative expenses	(192)	(215)	(194)	-11%	11%
Interest expense	(1,056)	(1,170)	(1,134)	-10%	3%
Interest income	310	244	245	27%	—%
Loss on extinguishment of debt	(188)	(68)	(13)	NM	NM
Other expense	(58)	(58)	(80)	—%	-28%
Other income	72	120	64	-40%	88%
Gain (loss) on disposal and sale of business interests	984	(52)	29	NM	NM
Asset impairment expense	(208)	(537)	(1,096)	-61%	-51%
Foreign currency transaction gains (losses)	(72)	42	(15)	NM	NM
Other non-operating expense	(147)	—	(2)	NM	-100%
Income tax expense	(708)	(990)	(32)	-28%	NM
Net equity in earnings of affiliates	39	71	36	-45%	97%
INCOME (LOSS) FROM CONTINUING OPERATIONS	1,349	(148)	191	NM	NM
Income (loss) from operations of discontinued businesses, net of income tax benefit (expense) of $(2), $(21), and $229, respectively	(9)	(18)	151	-50%	NM
Gain (loss) from disposal and impairments of discontinued businesses, net of income tax benefit (expense) of $(44), $0, and $266, respectively	225	(611)	(1,119)	NM	-45%
NET INCOME (LOSS)	1,565	(777)	(777)	NM	—%
Noncontrolling interests:					
Less: Income from continuing operations attributable to noncontrolling interests and redeemable stock of subsidiaries	(364)	(359)	(211)	1%	70%
Less: Loss (income) from discontinued operations attributable to noncontrolling interests	2	(25)	(142)	NM	-82%
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 1,203	$ (1,161)	$ (1,130)	NM	3%
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:					
Income (loss) from continuing operations, net of tax	$ 985	$ (507)	$ (20)	NM	NM
Income (loss) from discontinued operations, net of tax	218	(654)	(1,110)	NM	-41%
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 1,203	$ (1,161)	$ (1,130)	NM	3%
Net cash provided by operating activities	$ 2,343	$ 2,504	$ 2,897	-6%	-14%
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.53	$ 0.49	$ 0.45	8%	9%

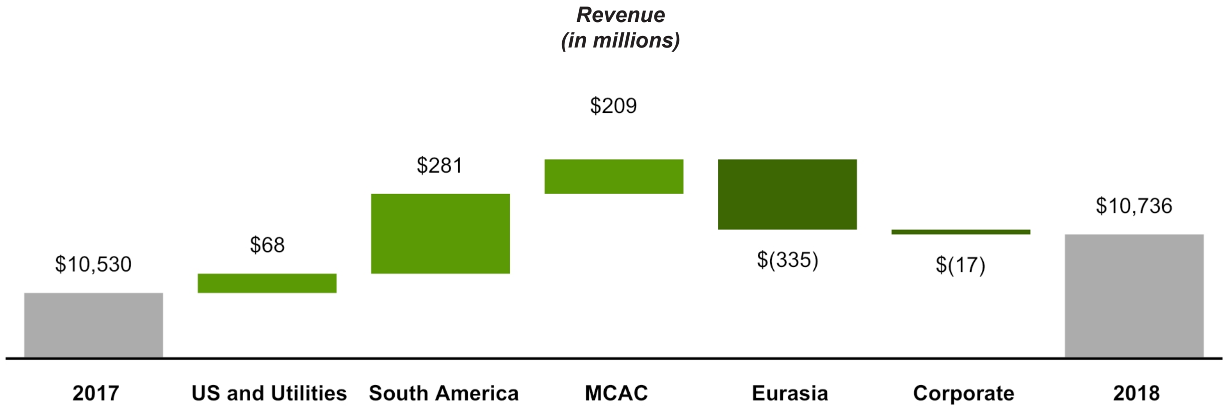
Components of Revenue, Cost of Sales and Operating Margin — Revenue includes revenue earned from the sale of energy from our utilities and the capacity and production of energy from our generation plants, which are classified as regulated and non-regulated, respectively, on the Consolidated Statements of Operations. Revenue also includes the gains or losses on derivatives associated with the sale of electricity.

Cost of sales includes costs incurred directly by the businesses in the ordinary course of business. Examples include electricity and fuel purchases, operations and maintenance costs, depreciation and amortization expense, bad debt expense and recoveries, and general administrative and support costs (including employee-related costs directly associated with the operations of the business). Cost of sales also includes the gains or losses on derivatives (including embedded derivatives other than foreign currency embedded derivatives) associated with the purchase of electricity or fuel.

Operating margin is defined as revenue less cost of sales.

Consolidated Revenue and Operating Margin

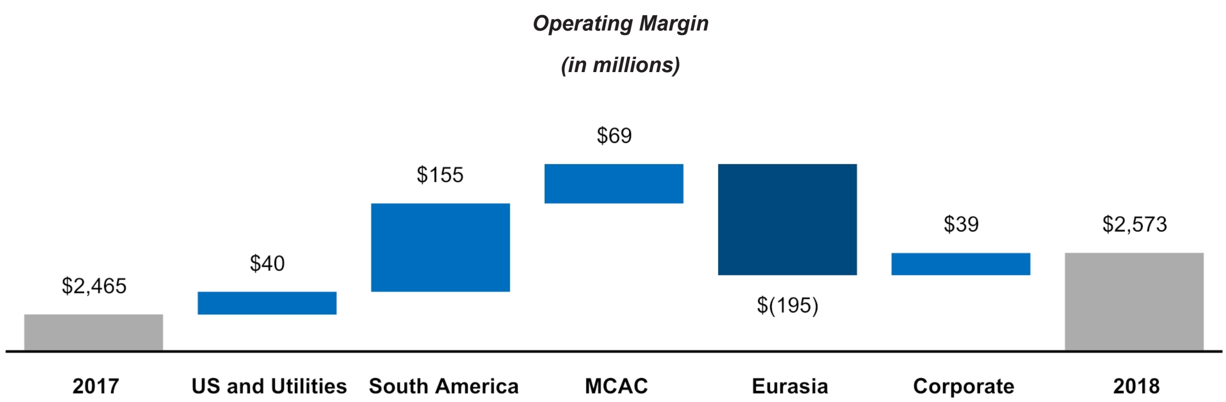
Year Ended December 31, 2018



Consolidated Revenue — Revenue increased $206 million, or 2%, in 2018 compared to 2017. Excluding the unfavorable FX impact of $52 million, primarily in South America partially offset by Eurasia, this increase was driven by:

- $357 million in South America primarily due to higher contract sales and prices in Colombia and the commencement of new PPAs at Angamos and Cochrane in Chile, as well as higher capacity prices in Argentina resulting from market reforms enacted in 2017;
- $215 million in MCAC primarily due to to the commencement of operations at the Colon combined cycle facility as well as improved hydrology at Panama, higher pass-through fuel prices in Mexico, higher contracted energy sales due to commencement of operations at the Los Mina combined cycle facility in June 2017, and higher spot prices in the Dominican Republic; and
- $68 million in US and Utilities driven primarily by higher market energy sales at Southland, higher regulated rates commencing in November 2017 at DPL, higher wholesale volume due to the new CCGT coming online as well as higher retail demand at IPL, and higher prices due to tariff reset and higher energy prices in El Salvador, partially offset by the sale and closure of several generation facilities at DPL.

These favorable impacts were partially offset by decreases of $366 million in Eurasia due to the sale of the Masinloc power plant in March 2018, as well as the sale of the Kazakhstan CHPs and expiration of the Kazakhstan HPP concession agreement in 2017.



Consolidated Operating Margin — Operating margin increased $108 million, or 4%, in 2018 compared to 2017. Excluding the favorable impact of FX of $8 million, primarily driven by Eurasia, this increase was driven by:

- $154 million in South America primarily due to the drivers discussed above and the absence of maintenance costs for planned outages in 2018 versus maintenance performed in Q3 2017 at Gener Chile;

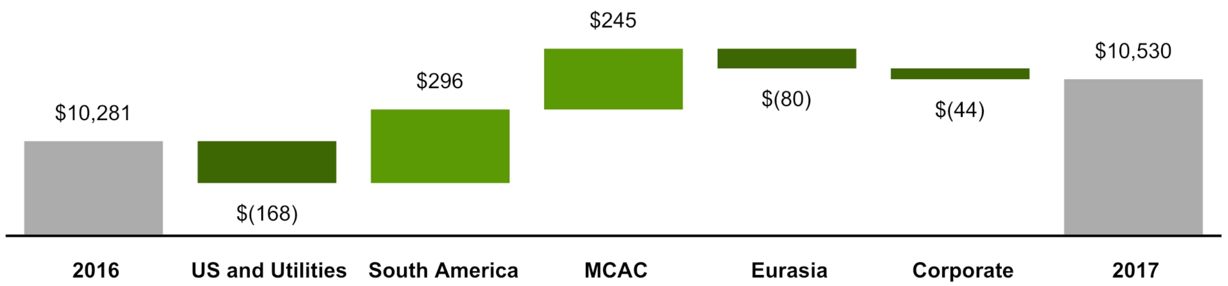
- $70 million in MCAC primarily due to drivers discussed above; and
- $40 million in US and Utilities mostly due to the drivers discussed above and the favorable impact of a one time reduction in the ARO liability at DPL's closed plants, Stuart and KIllen.

These favorable impacts were partially offset by a decrease of $204 million in Eurasia due to the drivers discussed above.

Year Ended December 31, 2017

Revenue

(in millions)



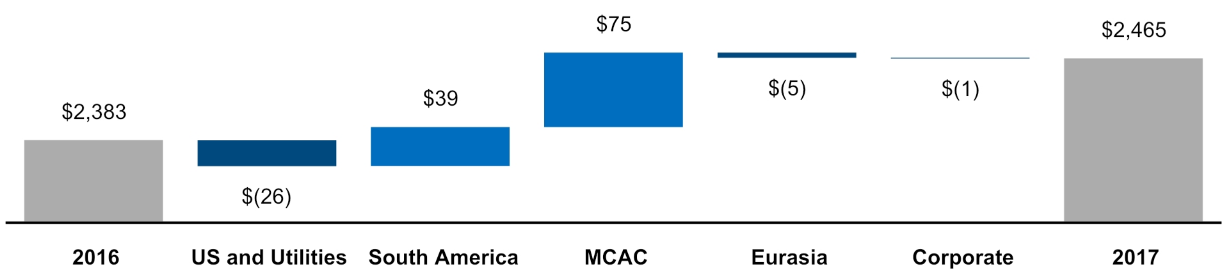
Consolidated Revenue — Revenue increased $249 million, or 2%, in 2017 compared to 2016. Excluding the net favorable FX impact of $38 million, primarily in South America, the increase was driven by:

- $249 million in South America primarily due to the start of commercial operations at Cochrane as well as higher availability at Argentina, partially offset by lower spot sales at Chivor; and
- $248 million in MCAC primarily due to the commencement of the combined cycle operations at Los Mina in June 2017 as well as higher rates in the Dominican Republic.

These favorable impacts were partially offset by decreases of $168 million in US & Utilities mainly due to lower retail tariffs, lower wholesale volume and price at DPL as well as hurricane impacts at Puerto Rico, partially offset by higher pass through costs in El Salvador.

Operating Margin

(in millions)



Consolidated Operating Margin — Operating margin increased $82 million, or 3%, in 2017 compared to 2016. Excluding the favorable impact of FX of $39 million, primarily in Brazil, Argentina, and Colombia, the increase was primarily driven by:

- $73 million in MCAC due to the commencement of the Los Mina combined cycle operations in June 2017 in the Dominican Republic as well as higher availability due to forced outages in 2016 at Mexico.

These positive impacts were partially offset by a decreases of $26 million in US and Utilities driven by lower retain margin, lower volumes, and lower commercial availability at DPL as well as a negative impact at IPL mainly due to one-off accruals due to the implementation of new base rates in Q2 2016.

See Item 7.—*Management's Discussion and Analysis of Financial Condition and Results of Operations—SBU Performance Analysis* of this Form 10-K for additional discussion and analysis of operating results for each SBU.

Consolidated Results of Operations — Other

General and administrative expenses

General and administrative expenses include expenses related to corporate staff functions and initiatives, executive management, finance, legal, human resources and information systems, as well as global development costs.

General and administrative expenses decreased $23 million, or 11%, to $192 million for 2018, compared to $215 million for 2017 primarily due to reduced people costs, professional fees and business development activity.

General and administrative expenses increased $21 million, or 11%, to $215 million for 2017, compared to $194 million for 2016 primarily due to severance costs related to workforce reductions associated with a major restructuring program, increased professional fees and increased business development activity.

Interest expense

Interest expense decreased $114 million, or 10%, to $1,056 million for 2018, compared to $1,170 million for 2017 primarily due to the reduction of debt at the Parent Company, favorable impacts from interest rate swaps in Chile and increased capitalized interest at Alto Maipo.

Interest expense increased $36 million, or 3%, to $1,170 million for 2017, compared to $1,134 million for 2016 primarily due to an increase at the South America SBU, driven by lower capitalized interest in 2017 due to the Cochrane plant starting commercial operations in the second half of 2016.

Interest income

Interest income increased $66 million, or 27%, to $310 million for 2018, compared to $244 million for 2017 primarily due to higher interest rates and increased long term receivables as a result of the adoption of the new revenue recognition standard. See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Interest income decreased $1 million in 2017 from 2016 with no material drivers.

Loss on extinguishment of debt

Loss on extinguishment of debt increased $120 million to $188 million for 2018, compared to $68 million for 2017. This increase was primarily due to higher losses at the Parent Company of $79 million from the redemption of senior notes and a prior year gain on early retirement of debt at AES Argentina of $65 million; partially offset by lower losses at other subsidiaries of $24 million in 2018.

Loss on extinguishment of debt increased $55 million to $68 million for 2017, compared to $13 million for 2016 primarily related to losses of $92 million, $20 million, and $9 million on debt extinguishments at the Parent Company, AES Gener, and IPALCO, respectively. The loss was partially offset by a gain on early retirement of debt at AES Argentina of $65 million.

Other income

Other income decreased $48 million, or 40%, to $72 million for 2018, compared to $120 million for 2017 primarily due to the 2017 favorable settlement of legal proceedings at Uruguaiana related to YPF's breach of the parties' gas supply agreement and a decrease in allowance for funds used during construction in the US and Utilities SBU. These decreases were partially offset by a gain on remeasurement of contingent liabilities for projects in Hawaii in 2018.

Other income increased $56 million, or 88%, to $120 million for 2017, compared to $64 million for 2016 primarily due to the 2017 favorable legal settlement mentioned above.

Other expense

Other expense remained flat at $58 million for 2018, compared to 2017 primarily due to a loss resulting from damage associated with a lightning incident at the Andres facility in the Dominican Republic in 2018 and higher non-service pension and other postretirement costs in 2018. This was offset by the 2017 write-off of water rights for projects that were no longer being pursued in the South America SBU and a loss on disposal of assets at DPL as a result of the decision to close the coal-fired and diesel-fired generating units at Stuart and Killen.

Other expense decreased $22 million, or 28%, to $58 million for 2017, compared to $80 million for 2016 primarily due to the 2016 recognition of a full allowance on a non-trade receivable in the MCAC SBU as a result of payment delays. This decrease was partially offset by the 2017 loss on disposal of assets at DPL as a result of the decision to close the coal-fired and diesel-fired generating units at Stuart and Killen and the write-off of water rights in the South America SBU for projects that are no longer being pursued.

See Note 19—*Other Income and Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Gain (loss) on disposal and sale of business interests

Gain on disposal and sale of business interests was $984 million for 2018 primarily due to the $772 million gain on sale of Masinloc and the $129 million and $69 million gains on sales of CTNG and Electrica Santiago, respectively, in Chile.

Loss on disposal and sale of business interests was $52 million for 2017 primarily due to the $49 million and $33 million losses on sale of Kazakhstan CHPs and HPPs, respectively, partially offset by the recognition of a $23 million gain related to the expiration of a contingency at Masinloc.

Gain on disposal and sale of business interests was $29 million for 2016 primarily due to the $49 million gain on sale of DPLER, partially offset by the $20 million loss on the deconsolidation of U.K. Wind.

See Note 23—*Held-For-Sale and Dispositions* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Goodwill impairment expense

There were no goodwill impairments for the years ended December 31, 2018, 2017, or 2016.

See Note 8—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Asset impairment expense

Asset impairment expense decreased $329 million, or 61%, to $208 million for 2018, compared to $537 million for 2017 mainly driven by prior year impairments of $186 million recognized in Kazakhstan due to the classification of the CHPs and HPPs as held-for-sale and $296 million in the U.S. as a result of the decision to sell the DPL peaker assets and a decline in forward pricing at Laurel Mountain, partially offset by a current year impairment of $157 million due to decreased future cash flows and the decision to sell Shady Point.

Asset impairment expense decreased $559 million, or 51%, to $537 million for 2017, compared to $1,096 million for 2016 mainly driven by the impairment of $859 million at DPL in 2016, partially offset by a $121 million impairment at Laurel Mountain in 2017 as a result of a decline in forward pricing.

See Note 20—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Foreign currency transaction gains (losses)

Foreign currency transaction gains (losses) in millions were as follows:

Years Ended December 31,	2018	2017	2016
Argentina [1]	$ (71)	$ 1	$ 37
Chile	(13)	8	(9)
Bulgaria	(6)	14	(8)
United Kingdom	(2)	(3)	13
Philippines	(1)	15	12
Mexico	—	17	(8)
Colombia	6	(23)	(8)
Corporate	11	3	(50)
Other	4	10	6
Total [2]	$ (72)	$ 42	$ (15)

(1) Primarily associated with the peso-denominated energy receivable indexed to the USD through the FONINVEMEM agreement which is considered a foreign currency derivative. See Note 6—*Financing Receivables* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

(2) Includes gains of $23 million, losses of $21 million, and gains of $17 million on foreign currency derivative contracts for the years ended December 31, 2018, 2017 and 2016, respectively.

The Company recognized net foreign currency transaction losses of $72 million for the year ended December 31, 2018 primarily due to the unrealized losses from the devaluation of receivables denominated in Argentine pesos and realized losses from Chilean pesos. These losses were partially offset by foreign currency derivative gains at the Parent Company.

The Company recognized net foreign currency transaction gains of $42 million for the year ended December 31, 2017 primarily driven by transactions associated with VAT activity in Mexico, the amortization of frozen embedded derivatives in the Philippines, and appreciation of the Euro in Bulgaria. These gains were partially offset by foreign currency derivative losses in Colombia due to a change in functional currency.

The Company recognized net foreign currency transaction losses of $15 million for the year ended December 31, 2016 primarily due to remeasurement losses on intercompany notes, and losses on swaps and options at the Parent Company. These losses were partially offset by foreign currency derivative gains related to government receivables in Argentina.

Other non-operating expense

Other non-operating expense was $147 million in 2018 primarily due to the $144 million other-than-temporary impairment of the Guacolda equity method investment as a result of increased renewable generation in Chile lowering energy prices and impacting the ability of Guacolda to re-contract its existing PPAs after they expire.

There were no significant other non-operating expenses in 2017 and 2016.

See Note 7—*Investments in and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Income tax expense

Income tax expense decreased $282 million to $708 million in 2018 as compared to $990 million for 2017. The Company's effective tax rates were 35% and 128% for the years ended December 31, 2018 and 2017, respectively.

The net decrease in the 2018 effective tax rate was primarily due to greater 2017 impacts related to U.S. tax reform one-time transition tax and remeasurement of deferred tax assets, relative to the 2018 U.S. tax reform impact to adjust the provisional estimate recorded under SAB 118, which provides SEC guidance on the application of the accounting standards for the initial enactment impacts of the TCJA. This net decrease was also attributable to the impact of the sale of the Company's entire 51% equity interest in Masinloc, offset by taxation of our foreign subsidiaries under U.S. GILTI rules.

Income tax expense increased $958 million to $990 million in 2017 as compared to $32 million for 2016. The Company's effective tax rates were 128% and 17% for the years ended December 31, 2017 and 2016, respectively.

The net increase in the 2017 effective tax rate was due primarily to the enactment of the TCJA in the U.S., partially offset by the impacts of the 2016 Chilean tax law reform and the 2016 devaluation of the Mexican peso. See Note 21—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding the 2016 Chilean income tax law reform.

Our effective tax rate reflects the tax effect of significant operations outside the U.S., which are generally taxed at rates different than the U.S. statutory rate. Foreign earnings may be taxed at rates higher than the U.S. corporate rate of 21% and are also subject to current U.S. taxation under the GILTI rules introduced by the TCJA. A future proportionate change in the composition of income before income taxes from foreign and domestic tax jurisdictions could impact our periodic effective tax rate. The Company also benefits from reduced tax rates in certain countries as a result of satisfying specific commitments regarding employment and capital investment. See Note 21—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional information regarding these reduced rates.

Net equity in earnings of affiliates

Net equity in earnings of affiliates decreased $32 million, or 45%, to $39 million for 2018, compared to $71 million for 2017 primarily due to losses at Fluence, which was formed in the first quarter of 2018, decreased income at Guacolda, and larger gains on projects that achieved commercial operations in 2017 than in 2018 at sPower, which was purchased in the third quarter of 2017.

Net equity in earnings of affiliates increased $35 million, or 97%, to $71 million in 2017, compared to $36 million for 2016 primarily due to earnings at the sPower equity method investment purchased in 2017, partially offset by fixed asset impairments in 2017 at the Distributed Energy entities, accounted for as equity affiliates.

See Note 7—*Investments In and Advances to Affiliates* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Net income (loss) from discontinued operations

Net income from discontinued operations was $216 million for the year ended December 31, 2018 primarily due to the after-tax gain on sale of Eletropaulo of $199 million recognized in the second quarter of 2018 and the recognition of a $26 million deferred gain upon liquidation of Borsod in October 2018.

Net loss from discontinued operations was $629 million for the year ended December 31, 2017 primarily due to the after-tax loss on deconsolidation of Eletropaulo of $611 million recognized in the fourth quarter of 2017. The remaining loss was due to a loss contingency recognized by our equity affiliate, partially offset by the income from operations of Eletropaulo prior to the date of deconsolidation.

Net loss from discontinued operations was $968 million for the year ended December 31, 2016 due to the sale of Sul, partially offset by the income from operations of Eletropaulo. The loss includes an after-tax loss on the impairment of Sul of $382 million recognized in the second quarter of 2016 and an additional after-tax loss on the sale of Sul of $737 million recognized upon disposal in October 2016. There was no significant loss from operations related to the Sul discontinued business.

See Note 22—*Discontinued Operations* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries decreased $22 million, or 6%, to $362 million in 2018, compared to $384 million in 2017. This decrease was primarily due to:

- Current year other-than-temporary impairment of Guacolda;
- Prior year favorable impact of a legal settlement at Uruguaiana; and
- Lower earnings due to deconsolidation of Eletropaulo in November 2017 and the sale of Masinloc in March 2018.

These decreases were partially offset by:

- Current year gains on sales of Electrica Santiago and CTNG in Chile;
- Higher earnings in Colombia primarily due to higher contract sales and prices; and
- Higher earnings in Vietnam due to the adoption of the new revenue recognition standard (See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information).

Net income attributable to noncontrolling interests and redeemable stock of subsidiaries increased $31 million, or 9%, to $384 million in 2017, compared to $353 million in 2016. This increase was primarily due to:

- Asset impairments at Buffalo Gap I and II in 2016.

These increases were partially offset by:

- Income tax benefits at Eletropaulo in 2016 (reflected within discontinued operations).

Net income (loss) attributable to The AES Corporation

Net income attributable to The AES Corporation increased $2,364 million to $1,203 million in 2018, compared to a loss of $1,161 million in 2017. This increase was primarily due to:

- Gains on the sales of Masinloc, Eletropaulo (reflected within discontinued operations), CTNG, and Electrica Santiago, and prior year losses on the sales of Kazakhstan CHPs and HPPs;
- Prior year loss on deconsolidation of Eletropaulo (reflected within discontinued operations);
- Prior year impact of U.S. tax reform enacted in December 2017;
- Prior year asset impairments at DPL, Laurel Mountain and in Kazakhstan;
- Lower interest expense at the Parent Company and Gener; and
- Higher margins at our South America, MCAC and US and Utilities SBUs.

These increases were partially offset by:

- Higher current year tax expense due to the new GILTI rules in the U.S.;
- Current year impairment at Shady Point;

- Current year other-than-temporary impairment of Guacolda;
- Higher losses on extinguishment of debt in the current year;
- Current year foreign exchange losses primarily due to the devaluation of the Argentine peso and foreign currency gains in the prior year;
- Prior year favorable impact of a legal settlement at Uruguaiana; and
- Lower margins in the current year at our Eurasia SBU as a result of the sales of Masinloc and Kazakhstan.

Net loss attributable to The AES Corporation increased $31 million, or 3%, to $1,161 million in 2017, compared to $1,130 million in 2016. This increase was primarily due to:

- Impact of U.S. tax reform enacted in December 2017;
- Losses on the sales of Kazakhstan CHPs and HPPs;
- Loss on deconsolidation of Eletropaulo (reflected within discontinued operations);
- Impairments at Laurel Mountain, Kilroot and in Kazakhstan; and
- Higher loss on extinguishment of debt.

These increases were partially offset by:

- Impairments at DPL in 2016;
- Loss on sale of Sul in 2016 (reflected within discontinued operations);
- Favorable impact of a legal settlement at Uruguaiana;
- Higher gains on foreign currency transactions; and
- Higher margins at our MCAC SBU.

SBU Performance Analysis

Segments

We are organized into four market-oriented SBUs: **US and Utilities** (United States, Puerto Rico and El Salvador); **South America** (Chile, Colombia, Argentina and Brazil); **MCAC** (Mexico, Central America and the Caribbean); and **Eurasia** (Europe and Asia). During the first quarter of 2018, the Andes and Brazil SBUs were merged in order to leverage scale and are now reported together as part of the South America SBU. Further, the Puerto Rico and El Salvador businesses, formerly part of the MCAC SBU, were combined with the US SBU, which is now reported as the US and Utilities SBU.

Non-GAAP Measures

Adjusted Operating Margin, Adjusted PTC and Adjusted EPS are non-GAAP supplemental measures that are used by management and external users of our Consolidated Financial Statements such as investors, industry analysts and lenders.

Effective January 1, 2018, the Company changed the definitions of Adjusted PTC and Adjusted EPS to exclude unrealized gains or losses from equity securities resulting from a newly effective accounting standard. We believe excluding these gains or losses provides a more accurate picture of continuing operations. Factors in this determination include the variability due to unrealized gains or losses related to equity securities remeasurement.

Adjusted Operating Margin

We define Adjusted Operating Margin as Operating Margin, adjusted for the impact of NCI, excluding (a) unrealized gains or losses related to derivative transactions; (b) benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures; and (c) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation. The allocation of HLBV earnings to noncontrolling interests is not adjusted out of Adjusted Operating Margin. See *Review of Consolidated Results of Operations* for definitions of Operating Margin and cost of sales.

The GAAP measure most comparable to Adjusted Operating Margin is Operating Margin. We believe that Adjusted Operating Margin better reflects the underlying business performance of the Company. Factors in this determination include the impact of NCI, where AES consolidates the results of a subsidiary that is not wholly owned by the Company, as well as the variability due to unrealized gains or losses related to derivative transactions and strategic decisions to dispose of or acquire business interests. Adjusted Operating Margin should not be construed as an alternative to Operating Margin, which is determined in accordance with GAAP.

Reconciliation of Adjusted Operating Margin (in millions)	Years Ended December 31,		
	2018	2017	2016
Operating Margin	$ 2,573	$ 2,465	$ 2,383
Noncontrolling interests adjustment [1]	(686)	(689)	(645)
Unrealized derivative losses (gains)	19	(5)	9
Disposition/acquisition losses	21	22	—
Restructuring costs [2]	1	22	—
Total Adjusted Operating Margin	$ 1,928	$ 1,815	$ 1,747

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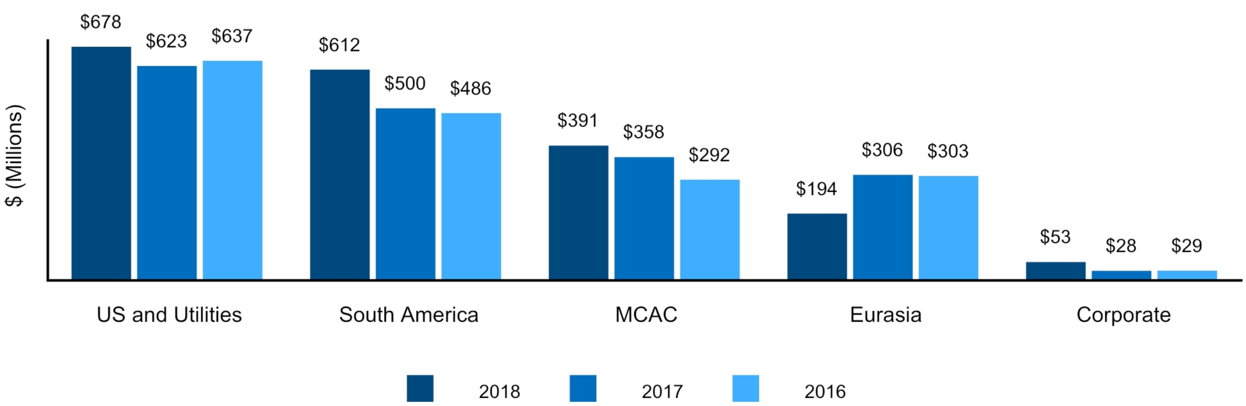
(1) The allocation of HLBV earnings to noncontrolling interests is not adjusted out of Adjusted Operating Margin.

(2) In February 2018, the Company announced a reorganization as a part of its ongoing strategy to simplify its portfolio, optimize its cost structure and reduce its carbon intensity.

Adjusted Operating Margin



Adjusted PTC

We define Adjusted PTC as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis adjusted for the same gains or losses excluded from consolidated entities.

Adjusted PTC reflects the impact of NCI and excludes the items specified in the definition above. In addition to the revenue and cost of sales reflected in Operating Margin, Adjusted PTC includes the other components of our Consolidated Statement of Operations, such as *general and administrative expenses* in the Corporate segment, as well as business development costs, *interest expense* and *interest income, other expense* and *other income, realized foreign currency transaction gains and losses,* and *net equity in earnings of affiliates*.

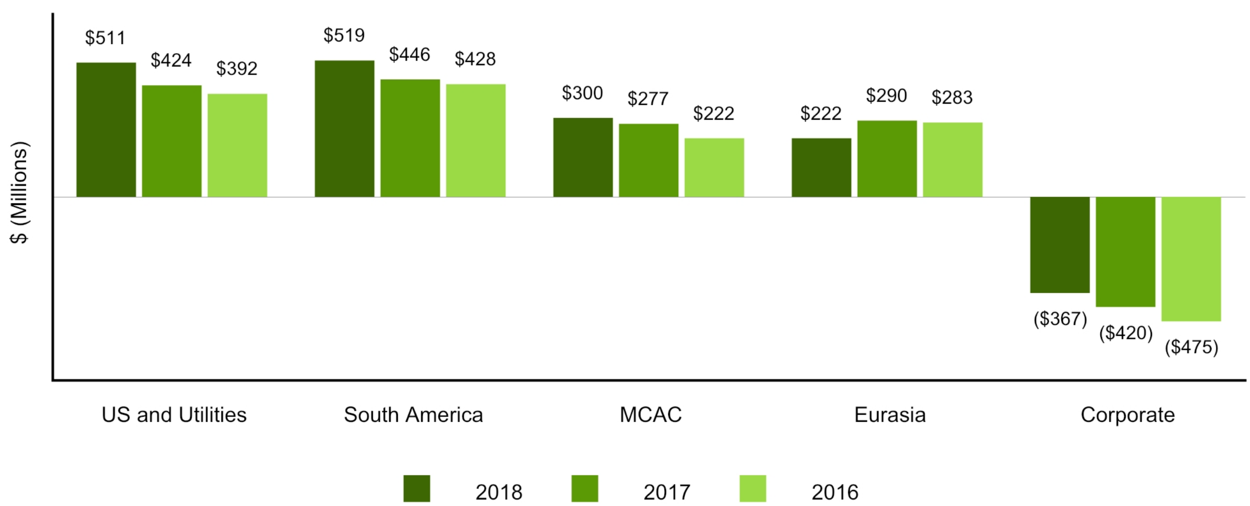
The GAAP measure most comparable to Adjusted PTC is *income from continuing operations attributable to The AES Corporation*. We believe that Adjusted PTC better reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose of or acquire business interests, retire debt or implement restructuring initiatives, which affect results in a given period or periods. In addition, earnings before tax represents the business performance of the Company before the application of statutory income tax rates and tax adjustments, including the effects of tax planning, corresponding to the various jurisdictions in which the Company operates. Given its large number of businesses and complexity, the Company concluded that Adjusted PTC is a more transparent measure that better assists investors in determining which businesses have the greatest impact on the Company's results.

Adjusted PTC should not be construed as an alternative to *income from continuing operations attributable to The AES Corporation*, which is determined in accordance with GAAP.

Reconciliation of Adjusted PTC (in millions)	Years Ended December 31,		
	2018	2017	2016
Income (loss) from continuing operations, net of tax, attributable to The AES Corporation	$ 985	$ (507)	$ (20)
Income tax expense (benefit) attributable to The AES Corporation	563	828	(111)
Pre-tax contribution	1,548	321	(131)
Unrealized derivative and equity securities losses (gains)	33	(3)	(9)
Unrealized foreign currency losses (gains)	51	(59)	22
Disposition/acquisition losses (gains)	(934)	123	6
Impairment expense	307	542	933
Loss on extinguishment of debt	180	62	29
Restructuring costs [1]	—	31	—
Total Adjusted PTC	$ 1,185	$ 1,017	$ 850

[1] In February 2018, the Company announced a reorganization as a part of its ongoing strategy to simplify its portfolio, optimize its cost structure and reduce its carbon intensity.

Adjusted PTC



Adjusted EPS

We define Adjusted EPS as diluted earnings per share from continuing operations excluding gains or losses of both consolidated entities and entities accounted for under the equity method due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures, and the tax impact from the repatriation of sales proceeds; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation; and (g) tax benefit or expense related to the enactment effects of 2017 U.S. tax law reform and related regulations and any subsequent period adjustments related to enactment effects.

The GAAP measure most comparable to Adjusted EPS is diluted earnings per share from continuing operations. We believe that Adjusted EPS better reflects the underlying business performance of the Company and is considered in the Company's internal evaluation of financial performance. Factors in this determination include the variability due to unrealized gains or losses related to derivative transactions or equity securities remeasurement, unrealized foreign currency gains or losses, losses due to impairments and strategic decisions to dispose of or acquire business interests, retire debt or implement restructuring initiatives, which affect results in a given period or periods. Adjusted EPS should not be construed as an alternative to diluted earnings per share from continuing operations, which is determined in accordance with GAAP.

The Company reported a loss from continuing operations of $0.77 and $0.04 per share for the years ended December 31, 2017 and 2016, respectively. For purposes of measuring diluted loss per share under GAAP, common stock equivalents were excluded from weighted average shares as their inclusion would be anti-dilutive. However, for purposes of computing Adjusted EPS, the Company has included the impact of anti-dilutive common stock equivalents. The table below reconciles the weighted average shares used in GAAP diluted loss per share to the weighted average shares used in calculating the non-GAAP measure of Adjusted EPS. No reconciliation is necessary for the year ended December 31, 2018 as the Company reported income from continuing operations.

Reconciliation of Denominator Used For Adjusted Earnings Per Share	**Year Ended December 31, 2017**			**Year Ended December 31, 2016**		
(in millions, except per share data)	**Loss**	**Shares**	**$ per share**	**Loss**	**Shares**	**$ per share**
GAAP DILUTED LOSS PER SHARE						
Loss from continuing operations attributable to The AES Corporation common stockholders	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)
EFFECT OF ANTI-DILUTIVE SECURITIES						
Restricted stock units	—	2	0.01	—	2	—
NON-GAAP DILUTED LOSS PER SHARE	$ (507)	662	$ (0.76)	$ (25)	662	$ (0.04)

Reconciliation of Adjusted EPS	**Years Ended December 31, 2018**	**2017**	**2016**
Diluted earnings (loss) per share from continuing operations	$ 1.48	$ (0.76)	$ (0.04)
Unrealized derivative and equity securities losses (gains)	0.05	—	(0.01)
Unrealized foreign currency losses (gains)	0.09 (1)	(0.10)	0.03
Disposition/acquisition losses (gains)	(1.41) (2)	0.19 (3)	0.01
Impairment expense	0.46 (4)	0.82 (5)	1.41 (6)
Loss on extinguishment of debt	0.27 (7)	0.09 (8)	0.05 (9)
Restructuring costs	—	0.05	—
U.S. Tax Law Reform Impact	0.18 (10)	1.08 (11)	—
Less: Net income tax expense (benefit)	0.12 (12)	(0.29) (13)	(0.51) (14)
Adjusted EPS	$ 1.24	$ 1.08	$ 0.94

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(1) Amount primarily relates to unrealized FX losses of $22 million, or $0.03 per share, associated with the devaluation of long-term receivables denominated in Argentine pesos, and unrealized FX losses of $14 million, or $0.02 per share, on intercompany receivables denominated in Euros and British pounds at the Parent Company.

(2) Amount primarily relates to gain on sale of Masinloc of $772 million, or $1.16 per share, gain on sale of CTNG of $86 million, or $0.13 per share, gain on sale of Electrica Santiago of $36 million, or $0.05 per share, gain on remeasurement of contingent consideration at AES Oahu of $32 million, or $0.05 per share, gain on sale related to the Company's contribution of AES Advancion energy storage to the Fluence joint venture of $23 million, or $0.03 per share and realized derivative gains associated with the sale of Eletropaulo of $21 million, or $0.03 per share; partially offset by loss on disposal of the Beckjord facility and additional shutdown costs related to Stuart and Killen at DPL of $21 million, or $0.03 per share.

(3) Amount primarily relates to loss on sale of Kazakhstan CHPs of $49 million, or $0.07 per share, realized derivative losses associated with the sale of Sul of $38 million, or $0.06 per share, loss on sale of Kazakhstan HPPs of $33 million, or $0.05 per share, and costs associated with early plant closures at DPL of $24 million, or $0.04 per share; partially offset by gain on Masinloc contingent consideration of $23 million, or $0.03 per share and gain on sale of Miami Fort and Zimmer of $13 million, or $0.02 per share.

(4) Amount primarily relates to asset impairments at Shady Point of $157 million, or $0.24 per share, and Nejapa of $37 million, or $0.06 per share, and other-than-temporary impairment of Guacolda of $96 million, or $0.14 per share.

(5) Amount primarily relates to asset impairments at Kazakhstan CHPs of $94 million, or $0.14 per share, at Kazakhstan HPPs of $92 million, or $0.14 per share, at Laurel Mountain of $121 million, or $0.18 per share, at DPL of $175 million, or $0.27 per share and at Kilroot of $37 million, or $0.05 per share.

(6) Amount primarily relates to asset impairments at DPL of $859 million, or $1.30 per share, at Buffalo Gap II of $159 million ($49 million, or $0.07 per share, net of NCI) and at Buffalo Gap I of $77 million ($23 million, or $0.03 per share, net of NCI).

(7) Amount primarily relates to loss on early retirement of debt at the Parent Company of $171 million, or $0.26 per share.

(8) Amount primarily relates to losses on early retirement of debt at the Parent Company of $92 million, or $0.14 per share, at AES Gener of $20 million, or $0.02 per share, and at IPALCO of $9 million or $0.01 per share; partially offset by a gain on early retirement of debt at AES Argentina of $65 million, or $0.10 per share.

(9) Amount primarily relates to the loss on early retirement of debt at the Parent Company of $19 million, or $0.03 per share.

(10) Amount relates to a SAB 118 charge to finalize the provisional estimate of one-time transition tax on foreign earnings of $194 million, or $0.29 per share, partially offset by a SAB 118 income tax benefit to finalize the provisional estimate of remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $77 million, or $0.11 per share.

(11) Amount relates to a one-time transition tax on foreign earnings of $675 million, or $1.02 per share and the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $39 million, or $0.06 per share.

(12) Amount primarily relates to the income tax expense under the GILTI provision associated with the gains on sales of business interests, primarily Masinloc, of $97 million, or $0.15 per share, and income tax expense associated with gains on sale of CTNG of $36 million, or $0.05 per share and Electrica Santiago of $13 million, or $0.02 per share; partially offset by income tax benefits associated with the loss on early retirement of debt at the Parent Company of $36 million, or $0.05 per share, and income tax benefits associated with the impairment at Shady Point of $33 million, or $0.05 per share.

(13) Amount primarily relates to the income tax benefit associated with asset impairments of $148 million, or $0.22 per share.

(14) Amount primarily relates to the income tax benefit associated with asset impairments of $332 million, or $0.50 per share.

US AND UTILITIES SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC (in millions) for the periods indicated:

For the Years Ended December 31,	2018	2017	2016	$ Change 2018 vs. 2017	% Change 2018 vs. 2017	$ Change 2017 vs. 2016	% Change 2017 vs. 2016
Operating Margin	$ 733	$ 693	$ 719	$ 40	6%	$ (26)	-4%
Adjusted Operating Margin [(1)]	678	623	637	55	9%	(14)	-2%
Adjusted PTC [(1)]	511	424	392	87	21%	32	8%

(1) A non-GAAP financial measure, adjusted for the impact of NCI. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2018 versus 2017

Operating Margin increased $40 million, or 6%, which was driven primarily by the following (in millions):

Increase at DPL primarily due to higher regulated rates following the approval of the 2017 ESP and the 2018 distribution rate order and favorable weather	$ 35
Increase at DPL driven by a one-time credit to depreciation expense, primarily as a result of a reduction in the ARO liability at DPL's closed plants, Stuart and Killen	32
Increase at IPL due to higher wholesale margins driven by Eagle Valley coming online and higher retail margins due to favorable weather	23
Increase at Southland driven by higher market energy sales, partially offset by a decrease in capacity sales and lower ancillary services due to the expiration of long-term agreements	12
Decrease at Hawaii primarily due to higher coal prices and lower gain on valuation of MTM commodity swaps	(24)
Impact of the sale and closure of generation plants at DPL	(12)
Decrease at IPL due to higher maintenance expense due to increased current year outages	(21)
Other	(5)
Total US and Utilities SBU Operating Margin Increase	**$ 40**

Adjusted Operating Margin increased $55 million primarily due to the drivers above, adjusted for a $24 million unrealized loss on coal derivatives in Hawaii partially offset by restructuring charges in the prior year.

Adjusted PTC increased $87 million, primarily driven by the increase in Adjusted Operating Margin described above, as well as an increase in the Company's share of earnings at Distributed Energy due to new solar project growth, lower interest expense and the HLBV allocation of noncontrolling interest earnings at Buffalo Gap, partially offset by lower allowance for equity funds used during construction at IPALCO.

Fiscal year 2017 versus 2016

Operating Margin decreased $26 million, or 4%, which was driven primarily by the following (in millions):

Decrease at DPL driven by lower retail margins due to lower regulated rates	$ (22)
Decrease at DPL primarily due to lower volumes due to the shutdown of Stuart Unit 1 and lower commercial availability	(21)
Decrease at IPL due to implementation of new base rates in Q2 2016 which resulted in a favorable change in accrual	(18)
Increase at DPL as a result of lower depreciation expense due to lower PP&E carrying values from impairments in 2016 and 2017	26
Other	9
Total US and Utilities SBU Operating Margin Decrease	**$ (26)**

Adjusted Operating Margin decreased $14 million primarily due to the drivers above, excluding unrealized gains and losses on derivatives, restructuring charges and costs associated with early plant closures.

Adjusted PTC increased $32 million, driven by earnings from equity affiliates due to the 2017 acquisition of sPower, the Company's share of earnings at Distributed Energy due to new solar project growth and an increase in insurance recoveries at DPL. The increase in Adjusted PTC was partially offset by the decrease of $14 million in Adjusted Operating Margin described above and a 2016 gain on contract termination at DP&L.

SOUTH AMERICA SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC (in millions) for the periods indicated:

For the Years Ended December 31,	2018	2017	2016	$ Change 2018 vs. 2017	% Change 2018 vs. 2017	$ Change 2017 vs. 2016	% Change 2017 vs. 2016
Operating Margin	$ 1,017	$ 862	$ 823	$ 155	18%	$ 39	5%
Adjusted Operating Margin [(1)]	612	500	486	112	22%	14	3%
Adjusted PTC [(1)]	519	446	428	73	16%	18	4%

(1) A non-GAAP financial measure, adjusted for the impact of NCI. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2018 versus 2017

Operating Margin increased $155 million, or 18%, which was driven primarily by the following (in millions):

Increase in Argentina mainly related to higher capacity prices resulting from market reforms enacted in 2017 and lower fixed costs primarily due to the devaluation of the Argentine peso	$ 71
Increase in Colombia mainly related to higher contract pricing in 2018 and higher generation	64
Margin on new PPAs in Chile at Gener, Angamos and Cochrane	50
Impact of the sale of Electrica Santiago	(38)
Lower fixed costs at Gener associated with planned maintenance performed in Q3 2017	21
Lower contract sales to distribution companies in Chile net of higher revenue associated with a contract termination	(24)
Other	11
Total South America SBU Operating Margin Increase	**$ 155**

Adjusted Operating Margin increased $112 million primarily due to the drivers above, adjusted for NCI.

Adjusted PTC increased $73 million, mainly due to the increase in Adjusted Operating Margin described above and lower interest in Chile, partially offset by a $28 million decrease associated with a gain recognized in the prior year from the settlement of a legal dispute with YPF at Uruguaiana, higher interest expense in Brazil, lower equity earnings in Chile and higher realized foreign currency losses in Argentina.

Fiscal year 2017 versus 2016

Including the favorable impact of foreign currency translation and remeasurement of $38 million, Operating Margin increased $39 million, or 5%, which was driven primarily by the following (in millions):

Start of operations at Cochrane Units I and II in July and October 2016, respectively	$ 72
Higher capacity payments in Argentina primarily due to changes in regulation in 2017	64
Net impact of volume and prices of lower energy purchased in spot market at Tietê	71
Higher contract sales at Chivor primarily due to an increase in contracted capacity at higher prices	35
Higher volume due to acquisition of new wind entities - Alto Sertão II	23
Favorable FX impacts at Tietê	21
Net impact of volume and prices of bilateral contracts due to higher energy purchased at Tietê	(100)
Negative impact in Gener due to new regulation on emissions (Green Taxes)	(41)
Lower spot sales at Chivor mainly due to lower generation and lower spot prices	(37)
Lower availability of efficient generation resulting in higher replacement energy and fixed costs, mainly associated with major maintenance at Ventanas Complex in Chile	(29)
Lower margin at the SING market primarily due to lower contract sales and increase in coal prices at Norgener partially offset by higher spot sales	(21)
Lower generation at CTSN mainly due to lower demand	(26)
Other	7
Total South America SBU Operating Margin Increase	**$ 39**

Adjusted Operating Margin increased $14 million primarily due to the drivers above, adjusted for NCI.

Adjusted PTC increased $18 million, driven by a $28 million increase from the settlement of a legal dispute with YPF at Uruguaiana in 2017 and the $14 million increase in Adjusted Operating Margin described above, as well as foreign currency gains in Argentina associated with the collection of financing receivables, prepayment of financial debt denominated in U.S. dollars in 2017 and lower foreign currency losses associated with the sale of Argentina's sovereign bonds at Termoandes. These positive impacts were partially offset by higher interest expense, mainly due to the acquisition of Alto Sertão II debt, issuance of debt at Argentina and lower interest capitalization in Cochrane and Chivor, and the write-off of water rights at Gener resulting from a business development project that is no longer pursued.

MCAC SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC (in millions) for the periods indicated:

For the Years Ended December 31,	2018	2017	2016	$ Change 2018 vs. 2017	% Change 2018 vs. 2017	$ Change 2017 vs. 2016	% Change 2017 vs. 2016
Operating Margin	$ 534	$ 465	$ 390	$ 69	15%	$ 75	19%
Adjusted Operating Margin [(1)]	391	358	292	33	9%	66	23%
Adjusted PTC [(1)]	300	277	222	23	8%	55	25%

(1) A non-GAAP financial measure, adjusted for the impact of NCI. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2018 versus 2017

Operating Margin increased $69 million, or 15%, which was driven primarily by the following (in millions):

Increase in Dominican Republic due to higher spot prices	$	32
Higher contracted energy sales in Panama mainly driven by the commencement of operations at the Colon combined cycle facility in September 2018		21
Higher availability driven by improved hydrology in Panama		17
Higher contracted energy sales in Dominican Republic mainly driven by the commencement of operations at the Los Mina combined cycle facility in June 2017 and lower forced maintenance outages		12
Decrease in Mexico due to pension plan pass-through adjustments and higher fuel costs		(8)
Other		(5)
Total MCAC SBU Operating Margin Increase	**$**	**69**

Adjusted Operating Margin increased $33 million primarily due to the drivers above, adjusted for NCI.

Adjusted PTC increased $23 million, mainly driven by the increase in Adjusted Operating Margin as described above, partially offset by lower capitalized interest due to project completions in Panama and Dominican Republic and lower foreign currency gains in Mexico.

Fiscal year 2017 versus 2016

Operating Margin increased $75 million, or 19%, which was driven primarily by the following (in millions):

Higher contracted energy sales in Dominican Republic net of LNG fuel consumption, mainly driven by Los Mina combined cycle commencement of operations in June 2017	$	34
Higher availability driven by improved hydrology in Panama		26
Higher availability in Mexico mainly driven by unplanned maintenance in 2016		13
Other		2
Total MCAC SBU Operating Margin Increase	**$**	**75**

Adjusted Operating Margin increased $66 million primarily due to the drivers above, adjusted for NCI.

Adjusted PTC increased $55 million, driven by the increase in Adjusted Operating Margin of $66 million as described above.

EURASIA SBU

The following table summarizes Operating Margin, Adjusted Operating Margin and Adjusted PTC (in millions) for the periods indicated:

For the Years Ended December 31,	2018	2017	2016	$ Change 2018 vs. 2017	% Change 2018 vs. 2017	$ Change 2017 vs. 2016	% Change 2017 vs. 2016
Operating Margin	$ 227	$ 422	$ 427	$ (195)	-46%	$ (5)	-1%
Adjusted Operating Margin (1)	194	306	303	(112)	-37%	3	1%
Adjusted PTC (1)	222	290	283	(68)	-23%	7	2%

(1) A non-GAAP financial measure, adjusted for the impact of NCI. See *SBU Performance Analysis—Non-GAAP Measures* for definition and Item 1.—*Business* for the respective ownership interest for key businesses.

Fiscal year 2018 versus 2017

Including favorable FX impacts of $8 million, Operating Margin decreased $195 million, or 46%, which was driven primarily by the following (in millions):

Impact of the sale of Masinloc power plant in March 2018	$	(122)
Impact of the sale of the Kazakhstan CHPs and the expiration of HPP concession in 2017		(36)
Decrease in Vietnam due to adoption of the new revenue recognition standard in 2018 and higher maintenance costs		(33)
Other		(4)
Total Eurasia SBU Operating Margin Decrease	**$**	**(195)**

Adjusted Operating Margin decreased $112 million, or 37%, primarily due to the drivers above, adjusted for NCI.

Adjusted PTC decreased $68 million, primarily driven by the decrease in Adjusted Operating Margin discussed above, partially offset by the positive impact in Vietnam due to increased interest income from the higher financing component of contract consideration as a result of adoption of the new revenue recognition standard in 2018. See Note 1—*General and Summary of Significant Accounting Policies—New Accounting Standards Adopted* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Fiscal year 2017 versus 2016

Operating Margin decreased $5 million, or 1%, and Adjusted Operating Margin increased $3 million, or 1%, with no material drivers.

Adjusted PTC increased $7 million, primarily driven by the increase in Adjusted Operating Margin, adjusted for NCI and excluding unrealized gains and losses on derivatives.

Key Trends and Uncertainties

During 2019 and beyond, we expect to face the following challenges at certain of our businesses. Management expects that improved operating performance at certain businesses, growth from new businesses, and global cost reduction initiatives may lessen or offset their impact. If these favorable effects do not occur, or if the challenges described below and elsewhere in this section impact us more significantly than we currently anticipate, or if volatile foreign currencies and commodities move more unfavorably, then these adverse factors (or other adverse factors unknown to us) may impact our operating margin, net income attributable to The AES Corporation and cash flows. We continue to monitor our operations and address challenges as they arise. For the risk factors related to our business, see Item 1.—*Business* and Item 1A.—*Risk Factors* of this Form 10-K.

Macroeconomic and Political

The macroeconomic and political environments in some countries where our subsidiaries conduct business have changed during 2018. This could result in significant impacts to tax laws and environmental and energy policies. Additionally, we operate in multiple countries and as such are subject to volatility in exchange rates at the subsidiary level. See Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk* for further information.

United States Tax Law Reform

In December 2017, the United States enacted the TCJA. The legislation significantly revised the U.S. corporate income tax system by, among other things, lowering the corporate income tax rate, introducing new limitations on interest expense deductions, subjecting foreign earnings in excess of an allowable return to current U.S. taxation, and adopting a semi-territorial corporate tax system. These changes impacted our 2018 effective tax rate and will materially impact our effective tax rate in future periods. Furthermore, we anticipate that higher U.S. tax expense may fully utilize our remaining net operating loss carryforwards in the near term, which could lead to material cash tax payments in the United States. Specific provisions of the TCJA and their potential impacts on the Company are noted below. Our interpretation of the TCJA may change as the U.S. Treasury and the Internal Revenue Service issue additional guidance. Such changes may be material.

Transition Tax — As further explained in Note 21—*Income Taxes* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K we have concluded our analysis of the implementation impacts of the TCJA and included adjustments to our previous estimates in accordance with the guidance of SAB 118. Our revised estimates took into account interpretative guidance issued in 2018 by the U.S. Treasury in proposed regulations. In the first quarter of 2019, the U.S. Treasury issued final regulations related to the one-time transition tax which further amended the guidance of the proposed regulations. We are still evaluating the final regulations which may have a material impact on our financial statements. The impacts of the final regulations will be reflected in our financial statements during the quarter ended March 31, 2019.

Limitation on Interest Expense Deductions — The TCJA introduced a new limitation on the deductibility of net interest expense beginning January 1, 2018. The deduction will be limited to interest income, plus 30 percent of tax basis EBITDA through 2021 (30 percent of EBIT beginning January 1, 2022). This determination is made at the consolidated group level, although it applies separately to partnerships. While interest expense of regulated utilities may be exempt from the limitation, the proposed regulations issued by the U.S. Treasury in 2018 would effectively limit interest expense of our U.S. utilities. The proposed regulations may change before they are fully enacted in final form and are not retroactive; we have not early adopted the proposed regulations. Given typical project financing and current U.S. holding company debt levels, we anticipate that this limitation will materially, negatively impact our effective tax rate.

Global Intangible Low Taxed Income ("GILTI") — The TCJA subjects the earnings of foreign subsidiaries to current U.S. taxation to the extent that those earnings exceed an allowable economic return on investment. The foreign earnings subject to current taxation under the GILTI provision are not limited to those derived from intangible property and may include gains derived from some future asset sales. The GILTI provision will subject a significant portion of our foreign earnings to current U.S. taxation. In 2018, the GILTI provision materially, negatively impacted our effective tax rate and we expect this to continue in future years. Prospectively, the consequences of the new GILTI provision may be partially mitigated by foreign tax credits. Proposed regulations were issued in 2018 by the U.S. Treasury which provided further guidance on GILTI and the related foreign tax credit, however there are further regulations expected and they may change before enacted in final form.

State Taxes — The reactions of the individual states to federal tax reform are still evolving. Most states will assess whether and how the federal changes will be incorporated into their state tax legislation. Some states have already decided whether to conform to new provisions of the federal tax law, such as the one-time transition tax and GILTI, while many other states have not yet enacted final legislation. As we expect higher taxable income in the future due to the federal changes, this may also lead to higher state taxable income. Our current state tax provisions predominantly have full valuation allowances against state net operating losses. These positions will be re-assessed in the future as state tax law evolves and may result in material changes in position.

Tax Equity Structures — Our U.S. renewable energy portfolio operates primarily through tax equity partnerships. We cannot be certain of the impacts U.S. tax reform may have on availability or pricing of tax equity for future growth opportunities. Impacts of provisions such as the lower tax rate and immediate expensing may impact the amount and timing of returns allocable to our partners in our existing tax equity structures.

Puerto Rico — Our subsidiaries in Puerto Rico have a long-term PPA with state-owned PREPA, which has been facing economic challenges that could result in a material adverse effect on our business in Puerto Rico.

The Puerto Rico Oversight, Management, and Economic Stability Act ("PROMESA") was enacted to create a structure for exercising federal oversight over the fiscal affairs of U.S. territories and created procedures for adjusting debt accumulated by the Puerto Rico government and, potentially, other territories ("Title III"). Finally, PROMESA expedites the approval of key energy projects and other critical projects in Puerto Rico.

PROMESA allowed for the establishment of an Oversight Board with broad powers of budgetary and financial control over Puerto Rico. The Oversight Board filed for bankruptcy on behalf of PREPA under Title III in July 2017. As a result of the bankruptcy filing, AES Puerto Rico and AES Ilumina's non-recourse debt of $317 million and $34 million, respectively, continue to be in default and are classified as current as of December 31, 2018. The Company is in compliance with its debt payment obligations as of December 31, 2018.

After the events of Hurricanes Irma and Maria in September 2017, Puerto Rico's infrastructure was severely damaged, including electric infrastructure and transmission lines. AES Puerto Rico resumed generation during the first quarter of 2018 and continues to be the lowest cost and EPA compliant energy provider in Puerto Rico and a critical supplier to PREPA. According to the US Federal Emergency Management Agency, as of January 2019 PREPA's recovery status is at 99%.

The Company's receivable balances in Puerto Rico as of December 31, 2018 totaled $68 million, of which $18 million was overdue. Despite the disruption caused by the hurricanes and the Title III protection, PREPA has been making substantially all of its payments to the generators in line with historical payment patterns.

A proposed Energy Public Policy law was introduced in October 2018 which includes the elimination of coal as a source for electricity generation by January 1, 2028 and the accelerated deployment of renewables (20% by 2025; 50% by 2040 and 100% by 2050). AES Puerto Rico's long-term PPA with PREPA expires December 31, 2027. Puerto Rico's Senate and House of Representatives are still debating certain amendments.

Considering the information available as of the filing date, Management believes the carrying amount of our assets in Puerto Rico of $598 million is recoverable as of December 31, 2018.

Argentina — During the second quarter of 2018, all of the three-year cumulative inflation rates commonly used to evaluate Argentina's inflation exceeded 100%. Therefore, Argentina's economy was determined to be highly inflationary. Since the tariffs and debt at our primary businesses in Argentina are denominated in USD, the functional currency of those businesses is USD. As such, the determination that the Argentina economy is highly inflationary is not expected to have a material impact on the Company's financial statements.

United Kingdom — In June 2016, the UK held a referendum in which voters approved an exit from the EU, commonly referred to as "Brexit." In January 2019, the UK parliament rejected a proposed withdrawal agreement that the EU had supported. The UK is expected to exit the EU on March 29, 2019. While the full impact of the Brexit remains uncertain, these changes are not expected to have a material adverse effect on our operations and consolidated financial results.

LIBOR Phase Out — In July 2017, the UK Financial Conduct Authority announced the phase out of LIBOR by the end of 2021. The Alternative Reference Rate Committee at the Federal Reserve is working to establish a new benchmark replacement rate. While AES maintains financial instruments that use LIBOR as an interest rate benchmark, the full impact of the phase out is uncertain until a new replacement benchmark is determined and implementation plans are more fully developed.

Regulatory

Maritza PPA Review — The DG Comp continues to review whether Maritza's PPA with NEK is compliant with the European Commission's state aid rules. Although no formal investigation has been launched by DG Comp to date, Maritza has engaged in discussions with the DG Comp case team and representatives of Bulgaria to discuss the agency's review. In the near term, Maritza expects that it will engage in discussions with Bulgaria to attempt to reach a negotiated resolution concerning DG Comp's review. The anticipated discussions could involve a range of potential outcomes, including but not limited to termination of the PPA and payment of some level of compensation to Maritza. Any negotiated resolution would be subject to mutually acceptable terms, lender consent, and DG Comp approval. At this time, we cannot predict the outcome of the anticipated discussions between Maritza and Bulgaria, nor can we predict how DG Comp might resolve its review if the discussions fail to result in an agreement concerning the review. Maritza believes that its PPA is legal and in compliance with all applicable laws, and it will take all actions necessary to protect its interests, whether through negotiated agreement or otherwise. However, there can be no assurances that this matter will be resolved favorably; if it is not, there could be a material adverse impact on Maritza's and the Company's respective financial statements.

Considering the information available as of the filing date, Management believes the carrying value of our long-lived assets at Maritza of approximately $1.1 billion is recoverable as of December 31, 2018.

Foreign Exchange

We operate in multiple countries and as such are subject to volatility in exchange rates at varying degrees at the subsidiary level and between our functional currency, the USD, and currencies of the countries in which we operate. In 2018, there was a significant devaluation in the Argentine peso against the USD, which had an impact on our 2018 results. Continued material devaluation of the Argentine peso against the USD could have an impact on our future results. For additional information, refer to Item 7A.—*Quantitative and Qualitative Disclosures About Market Risk.*

Alto Maipo

Alto Maipo has experienced cost overruns which have resulted in increased projected costs over the original $2 billion budget. Construction at the project is continuing, and the project is 75% complete.

In February 2018, Alto Maipo entered into a new construction contract with Strabag. The new contract is fixed-price and lump sum, transfers geological and construction risk to Strabag and provides a date certain for completion with strong performance and completion guarantees.

In May 2018, Alto Maipo and the project's senior lenders executed the financial restructuring of the project. The restructuring, among other things, includes additional funding commitments of up to $400 million of which $200 million was already contributed by AES Gener. Any unused portion of AES Gener's commitment will be used to prepay project debt.

If Alto Maipo is unable to meet certain construction milestones, there could be a material impact to the financing and value of the project which could have a material impact on the Company. The carrying value of long-lived assets and deferred tax assets of Alto Maipo as of December 31, 2018 was approximately $2 billion and $60 million, respectively. Management believes the carrying value of the long-lived asset group is recoverable as of December 31, 2018. In addition, Management believes it is more likely than not the deferred tax assets will be realized; however, the deferred tax assets could be reduced if estimates of future taxable income are decreased.

Andres

On September 3, 2018, lightning affected the Andres 319 MW combined cycle natural gas facility in the Dominican Republic ("the Plant") resulting in significant damage to its steam turbine and generator. The Company has business interruption and property damage insurance coverage, subject to pre-defined deductibles, under its existing programs.

On September 25, 2018, the Plant restarted operations running the gas turbine in simple cycle at partial load of approximately 120 MW. Management estimates that the Plant will operate the gas turbine in simple cycle at full load of approximately 185 MW starting in the second quarter of 2019, and in combined cycle at full capacity by the fourth quarter of 2019.

To mitigate the impact of the reduced capacity in the local energy market, the Company installed 120 MW of rental power (gas turbines) until the combined cycle facility is at full load. The rental units were fully operational beginning in December 2018.

Considering the information available as of the filing date, Management believes the carrying amount of our long-lived assets in Andres of $395 million is recoverable as of December 31, 2018.

Changuinola Tunnel Leak

Increased water levels were noted in a creek near the Changuinola power plant, a 223 MW hydroelectric power facility in Panama. After the completion of an assessment, the Company has confirmed loss of water in specific sections of the tunnel. The plant is in operation and can generate up to its maximum capacity. Repairs will be needed to ensure the long term performance of the facility, during which time the affected units of the plant will be out of service. Subject to final inspection, the repairs may take up to 10 months to complete and are expected to commence during the first quarter of 2019. The Company has notified its insurers of a potential claim and has asserted claims against its construction contractor. However, there can be no assurance of collection. The Company continues to monitor the situation to identify any potential changes to the tunnel. The Company has not identified any indicators of impairment and believes the carrying value of the long-lived asset group of $931 million is recoverable as of December 31, 2018.

Impairments

Long-lived Assets and Equity Affiliates **—** During the year ended December 31, 2018, the Company recognized asset and other-than-temporary impairment expense of $355 million. See Note 7—*Investments In and Advances To Affiliates* and Note 20—*Asset Impairment Expense* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information. After recognizing this impairment expense, the carrying value of the equity affiliates and the asset groups, including long-lived assets, and those asset groups that were assessed and not impaired, totaled $661 million at December 31, 2018.

Events or changes in circumstances that may necessitate recoverability tests and potential impairments of long-lived assets may include, but are not limited to, adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, or an expectation it is more likely than not the asset will be disposed of before the end of its estimated useful life.

Goodwill **—** The Company considers a reporting unit at risk of impairment when its fair value does not exceed its carrying amount by more than 10%. During the annual goodwill impairment test performed as of October 1, 2018, the Company determined that the fair value of its Gener reporting unit exceeded its carrying value by 7%. Therefore, Gener's $868 million goodwill balance was considered to be "at risk" as of December 31, 2018, largely due to the fact that a market participant would no longer assume perpetual cash flows from coal-fired power plants due to the increased penetration of renewable energy in Chile.

Through 2028, Gener’s plants remain largely contracted, with most of its PPAs expiring between 2029 and 2037. The Company utilized the income approach in deriving the fair value of the Gener reporting unit, which included estimated cash flows assuming a 20-year annuity for thermal generation and longer term cash flows for hydro generation. These cash flows were discounted using a weighted average cost of capital of 7%, which was determined based on the Capital Asset Pricing Model. See Item 7.—*Critical Accounting Policies and Estimates— Fair Value of Nonfinancial Assets and Liabilities* and Note 8—*Goodwill and Other Intangible Assets* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

The Company monitors its reporting units at risk of Step 1 failure on an ongoing basis, and believes that the estimates and assumptions used in the calculations are reasonable. Should the fair value of any of the Company’s reporting units fall below its carrying amount because of reduced operating performance, market declines, changes in the discount rate, regulatory changes, or other adverse conditions, goodwill impairment charges may be necessary in future periods.

Capital Resources and Liquidity

Overview — As of December 31, 2018, the Company had unrestricted cash and cash equivalents of $1.2 billion, of which $24 million was held at the Parent Company and qualified holding companies. The Company also had $313 million in short term investments, held primarily at subsidiaries. In addition, we had restricted cash and debt service reserves of $837 million. The Company also had non-recourse and recourse aggregate principal amounts of debt outstanding of $15.6 billion and $3.7 billion, respectively. Of the approximately $1.7 billion of our current non-recourse debt, $825 million was presented as such because it is due in the next twelve months, $351 million relates to debt considered in default due to covenant violations, and $483 million relates to debt at Colon which is in compliance with its covenants, but is presented as current since it is probable that the Company cannot meet a technical covenant requirement by its deadline. None of the defaults are payment defaults, but are instead technical defaults triggered by failure to comply with other covenants and/or other conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the Company. The Company expects to modify the Colon loan agreement in 2019 to amend the requirements of this technical covenant, after which the debt will be re-classified as noncurrent.

We expect such current maturities will be repaid from net cash provided by operating activities of the subsidiary to which the debt relates, through opportunistic refinancing activity or some combination thereof. We have $5 million of recourse debt which matures within the next twelve months. From time to time, we may elect to repurchase our outstanding debt through cash purchases, privately negotiated transactions or otherwise when management believes that such securities are attractively priced. Such repurchases, if any, will depend on prevailing market conditions, our liquidity requirements and other factors. The amounts involved in any such repurchases may be material.

We rely mainly on long-term debt obligations to fund our construction activities. We have, to the extent available at acceptable terms, utilized non-recourse debt to fund a significant portion of the capital expenditures and investments required to construct and acquire our electric power plants, distribution companies and related assets. Our non-recourse financing is designed to limit cross default risk to the Parent Company or other subsidiaries and affiliates. Our non-recourse long-term debt is a combination of fixed and variable interest rate instruments. Generally, a portion or all of the variable rate debt is fixed through the use of interest rate swaps. In addition, the debt is typically denominated in the currency that matches the currency of the revenue expected to be generated from the benefiting project, thereby reducing currency risk. In certain cases, the currency is matched through the use of derivative instruments. The majority of our non-recourse debt is funded by international commercial banks, with debt capacity supplemented by multilaterals, export credit agencies and local regional banks.

Given our long-term debt obligations, the Company is subject to interest rate risk on debt balances that accrue interest at variable rates. When possible, the Company will borrow funds at fixed interest rates or hedge its variable rate debt to fix its interest costs on such obligations. In addition, the Company has historically tried to maintain at least 70% of its consolidated long-term obligations at fixed interest rates, including fixing the interest rate through the use of interest rate swaps. These efforts apply to the notional amount of the swaps compared to the amount of related underlying debt. Presently, the Parent Company's only material unhedged exposure to variable interest rate debt relates to indebtedness under its $366 million outstanding secured term loan due 2022. On a consolidated basis, of the Company's $19.7 billion of total gross debt outstanding as of December 31, 2018, approximately $3.2 billion bore interest at variable rates that were not subject to a derivative instrument which fixed the interest rate. Brazil holds $1.1 billion of our floating rate non-recourse exposure as we have no ability to fix local debt interest rates efficiently.

In addition to utilizing non-recourse debt at a subsidiary level when available, the Parent Company provides a portion, or in certain instances all, of the remaining long-term financing or credit required to fund development, construction or acquisition of a particular project. These investments have generally taken the form of equity investments or intercompany loans, which are subordinated to the project's non-recourse loans. We generally obtain the funds for these investments from our cash flows from operations, proceeds from the sales of assets and/or the proceeds from our issuances of debt, common stock and other securities. Similarly, in certain of our businesses, the Parent Company may provide financial guarantees or other credit support for the benefit of counterparties who have entered into contracts for the purchase or sale of electricity, equipment or other services with our subsidiaries or lenders. In such circumstances, if a business defaults on its payment or supply obligation, the Parent Company will be responsible for the business' obligations up to the amount provided for in the relevant guarantee or other credit support. At December 31, 2018, the Parent Company had provided outstanding financial and performance-related guarantees or other credit support commitments to or for the benefit of our businesses, which were limited by the terms of the agreements, of approximately $712 million in aggregate (excluding those collateralized by letters of credit and other obligations discussed below).

As a result of the Parent Company's below investment grade rating, counterparties may be unwilling to accept our general unsecured commitments to provide credit support. Accordingly, with respect to both new and existing commitments, the Parent Company may be required to provide some other form of assurance, such as a letter of credit, to backstop or replace our credit support. The Parent Company may not be able to provide adequate assurances to such counterparties. To the extent we are required and able to provide letters of credit or other collateral to such counterparties, this will reduce the amount of credit available to us to meet our other liquidity needs. At December 31, 2018, we had $78 million in letters of credit outstanding, provided under our senior secured credit facility, $368 million in letters of credit outstanding, provided under our unsecured senior credit facility. These letters of credit operate to guarantee performance relating to certain project development and construction activities and business operations. During the year ended December 31, 2018, the Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts.

We expect to continue to seek, where possible, non-recourse debt financing in connection with the assets or businesses that we or our affiliates may develop, construct or acquire. However, depending on local and global market conditions and the unique characteristics of individual businesses, non-recourse debt may not be available on economically attractive terms or at all. If we decide not to provide any additional funding or credit support to a subsidiary project that is under construction or has near-term debt payment obligations and that subsidiary is unable to obtain additional non-recourse debt, such subsidiary may become insolvent, and we may lose our investment in that subsidiary. Additionally, if any of our subsidiaries lose a significant customer, the subsidiary may need to withdraw from a project or restructure the non-recourse debt financing. If we or the subsidiary choose not to proceed with a project or are unable to successfully complete a restructuring of the non-recourse debt, we may lose our investment in that subsidiary.

Many of our subsidiaries depend on timely and continued access to capital markets to manage their liquidity needs. The inability to raise capital on favorable terms, to refinance existing indebtedness or to fund operations and other commitments during times of political or economic uncertainty may have material adverse effects on the financial condition and results of operations of those subsidiaries. In addition, changes in the timing of tariff increases or delays in the regulatory determinations under the relevant concessions could affect the cash flows and results of operations of our businesses.

Long-Term Receivables — As of December 31, 2018, the Company had approximately $116 million of accounts receivable classified as *Other noncurrent assets* primarily related to certain of its generation businesses in Argentina. These noncurrent receivables mostly consist of accounts receivable in Argentina that, pursuant to amended agreements or government resolutions, have collection periods that extend beyond December 31, 2019, or one year from the latest balance sheet date. The majority of Argentinian receivables have been converted into long-term financing for the construction of power plants. See Note 6—*Financing Receivables* included in Item 8.—*Financial Statements and Supplementary Data* and Item 1.—*Business—Regulatory Matters—Argentina* of this Form 10-K for further information.

As of December 31, 2018, the Company had approximately $1.4 billion of loans receivable primarily related to the Mong Duong II facility constructed under a build, operate, and transfer contract in Vietnam. This loan receivable represents contract consideration related to the construction of the facility, which was substantially completed in 2015, and will be collected over the 25 year term of the plant's PPA. See Note 18—*Revenue* included in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for further information.

Cash Sources and Uses

The primary sources of cash for the Company in the year ended December 31, 2018 were cash flows from operating activities, proceeds from the sales of business interests, and debt financings. The primary uses of cash in the year ended December 31, 2018 were repayments of debt, capital expenditures, and purchases of short-term investments.

The primary sources of cash for the Company in the year ended December 31, 2017 were cash flows from operating activities, debt financings, and sales of short-term investments. The primary uses of cash in the year ended December 31, 2017 were repayments of debt, purchases of short-term investments, and capital expenditures.

The primary sources of cash for the Company in the year ended December 31, 2016 were cash flows from operating activities, debt financings, and sales of short-term investments. The primary uses of cash in the year ended December 31, 2016 were repayments of debt, purchases of short-term investments, and capital expenditures.

A summary of cash-based activities are as follows (in millions):

	Year Ended December 31, 2018	2017	2016
Cash Sources:			
Net income, adjusted for non-cash items [(1)]	$ 2,529	$ 2,569	$ 2,344
Proceeds from the sale of business interests, net of cash and restricted cash sold	2,020	108	538
Issuance of non-recourse debt	1,928	3,222	2,978
Borrowings under revolving credit facilities	1,865	2,156	1,465
Sale of short-term investments	1,302	3,540	4,904
Issuance of recourse debt	1,000	1,025	500
Contributions from noncontrolling interests and redeemable security holders	43	73	190
Release of working capital[(2)]	—	—	553
Other	175	102	171
Total Cash Sources	$ 10,862	$ 12,795	$ 13,643
Cash Uses:			
Repayments under revolving credit facilities	$ (2,238)	$ (1,742)	$ (1,433)
Capital expenditures	(2,121)	(2,177)	(2,345)
Repayments of recourse debt	(1,933)	(1,353)	(808)
Purchase of short-term investments	(1,411)	(3,310)	(5,151)
Repayments of non-recourse debt	(1,411)	(2,360)	(2,666)
Dividends paid on AES common stock	(344)	(317)	(290)
Distributions to noncontrolling interests	(340)	(424)	(476)
Payments for financed capital expenditures	(275)	(179)	(113)
Increase in working capital[(2)]	(186)	(65)	—
Contributions to equity affiliates	(145)	(89)	(6)
Acquisitions of businesses, net of cash acquired, and equity method investments	(66)	(609)	(52)
Payments for financing fees	(39)	(100)	(105)
Other	(138)	(242)	(189)
Total Cash Uses	$ (10,647)	$ (12,967)	$ (13,634)
Net increase (decrease) in Cash, Cash Equivalents, and Restricted Cash	$ 215	$ (172)	$ 9

(1) Refer to the table within the *Operating Activities* section below for a reconciliation of non-cash items affecting net income during the applicable period.
(2) Refer to the table within the *Operating Activities* section below for explanations of the variance in working capital requirements.

Consolidated Cash Flows

The following table reflects the changes in operating, investing, and financing cash flows for the comparative twelve month periods (in millions):

	December 31,			$ Change	
Cash flows provided by (used in):	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Operating activities	$ 2,343	$ 2,504	$ 2,897	$ (161)	$ (393)
Investing activities	(505)	(2,599)	(2,136)	2,094	(463)
Financing activities	(1,643)	43	(747)	(1,686)	790

Operating Activities

The following table summarizes the key components of our consolidated operating cash flows (in millions):

	December 31,			$ Change	
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
Net income (loss)	$ 1,565	$ (777)	$ (777)	$ 2,342	$ —
Depreciation and amortization	1,003	1,169	1,176	(166)	(7)
Loss (gain) on disposal and sale of business interests	(984)	52	(29)	(1,036)	81
Impairment expenses	355	537	1,098	(182)	(561)
Loss on extinguishment of debt	188	68	20	120	48
Deferred income taxes	313	672	(793)	(359)	1,465
Net loss (gain) from disposal and impairments of discontinued businesses	(269)	611	1,383	(880)	(772)
Other adjustments to net income	358	237	266	121	(29)
Non-cash adjustments to net income (loss)	964	3,346	3,121	(2,382)	225
Net income, adjusted for non-cash items	$ 2,529	$ 2,569	$ 2,344	$ (40)	$ 225
Changes in working capital [(1)]	(186)	(65)	553	(121)	(618)
Net cash provided by operating activities [(2)]	$ 2,343	$ 2,504	$ 2,897	$ (161)	$ (393)

(1) Refer to the table below for explanations of the variance in operating assets and liabilities.
(2) Amounts included in the table above include the results of discontinued operations, where applicable.

Fiscal Year 2018 versus 2017

Cash provided by operating activities decreased $161 million for the year ended December 31, 2018, compared to December 31, 2017, primarily driven by a decrease in net income, adjusted for non-cash items of $40 million, and a $121 million increase in working capital requirements.

The increase in working capital requirements of $121 million for the year ended December 31, 2018, compared to December 31, 2017, was primarily driven by (in millions):

Decreases in operating cash flow resulting from changes in:		
Prepaid expenses and other current assets, primarily due to an insurance recovery receivable at Andres, advance payments to gas suppliers at Colon, and prior year collections of net regulatory assets at Eletropaulo, which was deconsolidated in Q4 2017; partially offset by the impact of the sales of Miami Fort and Zimmer and the retirement of the Stuart facility at DPL	$	(129)
Accounts payable and other current liabilities, primarily due to the deconsolidation of Eletropaulo in Q4 2017 and the timing of payments on coal purchases at Gener; partially offset by the timing of payments on coal purchases at Puerto Rico		(101)
Other liabilities, primarily due to the deconsolidation of Eletropaulo in Q4 2017; partially offset by a prior year decrease in deferred tax and derivative liabilities at the Parent Company		(57)
Accounts receivable, primarily due to lower collections at Los Mina and Itabo, and higher sales at Colon and Chivor; partially offset by the deconsolidation of Eletropaulo in Q4 2017 and higher CAMMESA collections at Alicura		(29)
Increases in operating cash flow resulting from changes in:		
Other assets, primarily related to the deconsolidation of Eletropaulo in Q4 2017 and collections on the construction performance obligation from the offtaker at Vietnam		263
Other		(68)
Total decrease in operating cash flow from higher working capital requirements	$	(121)

Fiscal Year 2017 versus 2016

Cash provided by operating activities decreased $393 million for the year ended December 31, 2017, compared to December 31, 2016, primarily driven by an increase in net income, adjusted for non-cash items of $225 million and a $618 million increase in working capital requirements.

The increase in working capital requirements of $618 million for the year ended December 31, 2017, compared to December 31, 2016, was primarily driven by (in millions):

Decreases in operating cash flow resulting from changes in:		
Prepaid expenses and other current assets, primarily short-term regulatory assets at Eletropaulo and Sul	$	(763)
Accounts receivable, primarily at Maritza and Eletropaulo		(414)
Other liabilities, primarily due to higher deferrals into regulatory liabilities related to energy costs in 2016 compared to 2017 at Eletropaulo		(361)
Increases in operating cash flow resulting from changes in:		
Accounts payable and other current liabilities, primarily at Eletropaulo, Tietê, Gener and Maritza; partially offset at the Parent Company		782
Income taxes payable, net, and other taxes payable, primarily at Gener, Tietê and Eletropaulo		252
Other		(114)
Total decrease in operating cash flow from higher working capital requirements	$	(618)

Investing Activities

Fiscal Year 2018 versus 2017

Net cash used in investing activities decreased $2,094 million for the year ended December 31, 2018 compared to December 31, 2017, which was primarily driven by (in millions):

Increases in:		
Proceeds from the sales of business interests, net of cash and restricted cash sold, primarily due to the current year sales of Masinloc, Electrica Santiago, Eletropaulo, CTNG and the DPL Peaker assets, partially offset by the sale of the Kazakhstan CHPs in 2017 and transaction costs incurred for the Beckjord sale	$	1,912
Decreases in:		
Payments for the acquisitions of business interests, net of cash and restricted cash acquired, primarily due to the acquisitions of sPower and Alto Sertão II in 2017		543
Capital expenditures [1]		56
Cash resulting from net purchases of short-term investments		(339)
Other investing activities		(78)
Total decrease in net cash used in investing activities	$	2,094

[1] Refer to the tables below for a breakout of capital expenditure by type and by primary business driver.

The following table summarizes the Company's capital expenditures for growth investments, maintenance, and environmental reported in investing cash activities for the periods indicated (in millions):

	December 31, 2018	2017	$ Change
Growth Investments	$ 1,663	$ 1,549	$ 114
Maintenance	423	552	(129)
Environmental	35	76	(41)
Total capital expenditures	$ 2,121	$ 2,177	$ (56)

Cash used for capital expenditures decreased $56 million for the year ended December 31, 2018 compared to December 31, 2017, which was primarily driven by (in millions):

Decreases in:	
Growth expenditures at the MCAC SBU, primarily related to the completion of the Colon project, and lower spending at Los Mina due to the completion of the Combined Cycle project	$ (242)
Maintenance and environmental expenditures at the South America SBU, primarily due to the deconsolidation of Eletropaulo in Q4 2017	(183)
Increases in:	
Growth expenditures at the US and Utilities SBU, primarily due to increased spending for the Southland re-powering project	373
Other capital expenditures	(4)
Total decrease in capital expenditures	$ (56)

Fiscal Year 2017 versus 2016

Net cash used in investing activities increased $463 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Increases in:	
Payments for the acquisitions of businesses, net of cash and restricted cash acquired, and equity method investees (related to the acquisitions of sPower and Alto Sertão II in 2017, partially offset by reduced acquisitions of Distributed Energy projects in 2016)	$ (557)
Contributions to equity investments at OPGC and sPower	(83)
Cash resulting from net sales of short-term investments	477
Decreases in:	
Proceeds from the sale of business, net of cash and restricted cash sold, related to the sale of Sul in 2016, partially offset by the sale of Zimmer and Miami Fort	(430)
Capital expenditures [1]	168
Other investing activities	(38)
Total increase in net cash used in investing activities	$ (463)

[1] Refer to the tables below for a breakout of capital expenditures by type and by primary business driver.

The following table summarizes the Company's capital expenditures for growth investments, maintenance and environmental for the periods indicated (in millions):

	December 31, 2017	2016	$ Change
Growth Investments	$ 1,549	$ 1,510	$ 39
Maintenance	552	617	(65)
Environmental [1]	76	218	(142)
Total capital expenditures	$ 2,177	$ 2,345	$ (168)

[1] Includes both recoverable and non-recoverable environmental capital expenditures.

Cash used for capital expenditures decreased by $168 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Decreases in:		
Growth expenditures at the South America SBU, primarily due to the completion of the Cochrane project and slower than anticipated productivity by construction contractors at Alto Maipo	$	(114)
Growth expenditures at the Eurasia SBU, primarily due to timing of payments resulting in more financed capex		(73)
Maintenance and environmental expenditures at the US and Utilities SBU, primarily due to lower spending at IPALCO on the NPDES and MATS compliance and Harding Street refueling projects, decreased spending on CCR compliance, and decreased spending at DPL on Stuart and Killen facilities due to planned plant closures		(180)
Increases in:		
Growth expenditures at the US and Utilities SBU, primarily due to increased spending for the Southland re-powering project and various Distributed Energy projects; partially offset by lower spending related to Eagle Valley at IPALCO		233
Other capital expenditures		(34)
Total decrease in capital expenditures	$	(168)

Financing Activities

Net cash used in financing activities increased $1,686 million for the year ended December 31, 2018 compared to December 31, 2017, which was primarily driven by (in millions):

Increases in:		
Net repayments of recourse debt at the Parent Company [(1)]	$	(605)
Net repayments of non-recourse debt at Angamos, DPL, Chivor, and Maritza		(372)
Net repayments on revolving credit facilities at IPALCO and Gener		(370)
Net issuance of non-recourse debt at Southland		199
Decreases in:		
Net issuance of non-recourse debt at AES Argentina, Tietê, Colon, Alto Maipo, US Generation, and Los Mina		(614)
Net borrowing on revolving credit facilities at the Parent Company		(413)
Net repayments of non-recourse debt at IPALCO and Gener		518
Other financing activities		(29)
Total increase in net cash used in financing activities	$	(1,686)

(1) See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for more information regarding significant recourse debt transactions.

Net cash provided by financing activities increased $790 million for the year ended December 31, 2017 compared to December 31, 2016, which was primarily driven by (in millions):

Increases in:		
Net issuance of non-recourse debt at Southland, Tiete, Eletropaulo, AES Argentina, and Colon	$	1,396
Net repayments of non-recourse debt at Gener and IPALCO		(628)
Net borrowing on revolving credit facilities at the Parent Company and Gener		297
Decreases in:		
Net repayments on revolving credit facilities at IPALCO		123
Net issuance of non-recourse debt at Cochrane		(170)
Proceeds from the sale of redeemable stock of subsidiaries at IPALCO		(134)
Contributions from noncontrolling interests and redeemable security holders at Colon, IPALCO, and Distributed Energy		(117)
Other financing activities		23
Total Increase in net cash provided by financing activities	$	790

Parent Company Liquidity

The following discussion of Parent Company Liquidity is included as a useful measure of the liquidity available to The AES Corporation, or the Parent Company, given the non-recourse nature of most of our indebtedness. Parent Company Liquidity as outlined below is a non-GAAP measure and should not be construed as an alternative to *cash and cash equivalents* which is determined in accordance with GAAP. Parent Company Liquidity may differ from similarly titled measures used by other companies. The principal sources of liquidity at the Parent Company level are dividends and other distributions from our subsidiaries, including refinancing proceeds, proceeds from debt and equity financings at the Parent Company level, including availability under our credit facilities, and proceeds from asset sales. Cash requirements at the Parent Company level are primarily to fund interest; principal repayments of debt; construction commitments; other equity commitments; common stock repurchases; acquisitions; taxes; Parent Company overhead and development costs; and dividends on common stock.

The Company defines Parent Company Liquidity as cash available to the Parent Company plus available borrowings under existing credit facilities plus cash at qualified holding companies. The cash held at qualified holding companies represents cash sent to subsidiaries of the Company domiciled outside of the U.S. Such subsidiaries have no contractual restrictions on their ability to send cash to the Parent Company. Parent Company

Liquidity is reconciled to its most directly comparable U.S. GAAP financial measure, *Cash and cash equivalents*, at December 31, 2018 and 2017 as follows:

Parent Company Liquidity (in millions)	2018	2017
Consolidated cash and cash equivalents	$ 1,166	$ 949
Less: Cash and cash equivalents at subsidiaries	(1,142)	(938)
Parent and qualified holding companies' cash and cash equivalents	24	11
Commitments under Parent Company credit facilities	1,100	1,100
Less: Letters of credit under the credit facilities	(78)	(35)
Less: Borrowings under the credit facilities	—	(207)
Borrowings available under Parent Company credit facilities	1,022	858
Total Parent Company Liquidity	$ 1,046	$ 869

The Parent Company paid dividends of $0.52 per share to its common stockholders during the year ended December 31, 2018. While we intend to continue payment of dividends and believe we will have sufficient liquidity to do so, we can provide no assurance that we will continue to pay dividends, or if continued, the amount of such dividends.

Recourse Debt

Our total recourse debt was $3.7 billion and $4.6 billion at December 31, 2018 and 2017, respectively. See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

While we believe that our sources of liquidity will be adequate to meet our needs for the foreseeable future, this belief is based on a number of material assumptions, including, without limitation, assumptions about our ability to access the capital markets, the operating and financial performance of our subsidiaries, currency exchange rates, power market pool prices, and the ability of our subsidiaries to pay dividends. In addition, our subsidiaries' ability to declare and pay cash dividends to us (at the Parent Company level) is subject to certain limitations contained in loans, governmental provisions and other agreements. We can provide no assurance that these sources will be available when needed or that the actual cash requirements will not be greater than anticipated. See Item 1A.—*Risk Factors—The AES Corporation is a holding company and its ability to make payments on its outstanding indebtedness, including its public debt securities, is dependent upon the receipt of funds from its subsidiaries by way of dividends, fees, interest, loans or otherwise,* of this Form 10-K.

Various debt instruments at the Parent Company level, including our senior secured credit facilities, contain certain restrictive covenants. The covenants provide for, among other items, limitations on other indebtedness; liens, investments and guarantees; limitations on dividends, stock repurchases and other equity transactions; restrictions and limitations on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet and derivative arrangements; maintenance of certain financial ratios; and financial and other reporting requirements. As of December 31, 2018, we were in compliance with these covenants at the Parent Company level.

Non-Recourse Debt

While the lenders under our non-recourse debt financings generally do not have direct recourse to the Parent Company, defaults thereunder can still have important consequences for our results of operations and liquidity, including, without limitation:

- reducing our cash flows as the subsidiary will typically be prohibited from distributing cash to the Parent Company during the time period of any default;
- triggering our obligation to make payments under any financial guarantee, letter of credit or other credit support we have provided to or on behalf of such subsidiary;
- causing us to record a loss in the event the lender forecloses on the assets; and
- triggering defaults in our outstanding debt at the Parent Company.

For example, our senior secured credit facilities and outstanding debt securities at the Parent Company include events of default for certain bankruptcy related events involving material subsidiaries. In addition, our revolving credit agreement at the Parent Company includes events of default related to payment defaults and accelerations of outstanding debt of material subsidiaries.

Some of our subsidiaries are currently in default with respect to all or a portion of their outstanding indebtedness. The total non-recourse debt classified as current in the accompanying Consolidated Balance Sheets amounts to $1.7 billion. As of December 31, 2018, $351 million of non-recourse debt was current related to such defaults at two subsidiaries, AES Puerto Rico and AES Ilumina, and $483 million relates to debt at Colon which is in compliance with its covenants, but is presented as current since it is probable that the Company cannot meet a technical covenant requirement by its deadline. The Company expects to modify the Colon loan agreement in 2019 to amend the requirements of this technical covenant, after which the debt will be re-classified as noncurrent. See Note 10—*Debt* in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K for additional detail.

None of the subsidiaries that are currently in default are subsidiaries that met the applicable definition of materiality under AES' corporate debt agreements as of December 31, 2018 in order for such defaults to trigger an event of default or permit acceleration under AES' indebtedness. However, as a result of additional dispositions of assets, other significant reductions in asset carrying values or other matters in the future that may impact our financial position and results of operations or the financial position of the individual subsidiary, it is possible that one or more of these subsidiaries could fall within the definition of a "material subsidiary" and thereby upon an acceleration, trigger an event of default and possible acceleration of the indebtedness under the Parent Company's outstanding debt securities. A material subsidiary is defined in the Company's senior secured revolving credit facilities as any business that contributed 20% or more of the Parent Company's total cash distributions from businesses for the four most recently completed fiscal quarters. As of December 31, 2018, none of the defaults listed above individually or in the aggregate results in or is at risk of triggering a cross-default under the recourse debt of the Company.

Contractual Obligations and Parent Company Contingent Contractual Obligations

A summary of our contractual obligations, commitments and other liabilities as of December 31, 2018 is presented below and excludes any businesses classified as discontinued operations or held-for-sale (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years	Other	Footnote Reference[4]
Debt obligations [1]	$ 19,687	$ 1,701	$ 3,567	$ 4,407	$ 10,012	$ —	10
Interest payments on long-term debt [2]	6,967	846	1,625	1,194	3,302	—	n/a
Capital lease obligations	12	1	2	2	7	—	11
Operating lease obligations	643	74	63	51	455	—	11
Electricity obligations	7,573	786	973	627	5,187	—	11
Fuel obligations	6,175	1,494	1,909	1,038	1,734	—	11
Other purchase obligations	3,944	1,375	1,017	774	778	—	11
Other long-term liabilities reflected on AES' consolidated balance sheet under GAAP [3]	809	—	263	207	326	13	n/a
Total	$ 45,810	$ 6,277	$ 9,419	$ 8,300	$ 21,801	$ 13	

(1) Includes recourse and non-recourse debt presented on the Consolidated Balance Sheet. These amounts exclude capital lease obligations which are included in the capital lease category.

(2) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or new debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2018.

(3) These amounts do not include current liabilities on the Consolidated Balance Sheet except for the current portion of uncertain tax obligations. Noncurrent uncertain tax obligations are reflected in the "Other" column of the table above as the Company is not able to reasonably estimate the timing of the future payments. In addition, these amounts do not include: (1) regulatory liabilities (See Note 9—*Regulatory Assets and Liabilities*), (2) contingencies (See Note 12—*Contingencies*), (3) pension and other postretirement employee benefit liabilities (see Note 13—*Benefit Plans*), (4) derivatives and incentive compensation (See Note 5—*Derivative Instruments and Hedging Activities*) or (5) any taxes (See Note 21—*Income Taxes*) except for uncertain tax obligations, as the Company is not able to reasonably estimate the timing of future payments. See the indicated notes to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information on the items excluded.

(4) For further information see the note referenced below in Item 8.—*Financial Statements and Supplementary Data* of this Form 10-K.

The following table presents our Parent Company's contingent contractual obligations as of December 31, 2018:

Contingent contractual obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 685	33	$0 — 157
Letters of credit under the unsecured credit facility	368	10	$1 — 247
Letters of credit under the senior secured credit facility	78	23	$0 — 49
Asset sale related indemnities [1]	27	1	$27
Total	$ 1,158	67	

(1) Excludes normal and customary representations and warranties in agreements for the sale of assets (including ownership in associated legal entities) where the associated risk is considered to be nominal.

We have a diverse portfolio of performance-related contingent contractual obligations. These obligations are designed to cover potential risks and only require payment if certain targets are not met or certain contingencies occur. The risks associated with these obligations include change of control, construction cost overruns, subsidiary default, political risk, tax indemnities, spot market power prices, sponsor support and liquidated damages under power sales agreements for projects in development, in operation and under construction. In addition, we have an asset sale program through which we may have customary indemnity obligations under certain assets sale agreements. While we do not expect that we will be required to fund any material amounts under these contingent contractual obligations beyond 2018, many of the events which would give rise to such obligations are beyond our control. We can provide no assurance that we will be able to fund our obligations under these contingent contractual obligations if we are required to make substantial payments thereunder.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements of AES are prepared in conformity with U.S. GAAP, which requires the use of estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. AES' significant accounting policies are described in Note 1—*General and Summary of Significant Accounting Policies* to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

An accounting estimate is considered critical if the estimate requires management to make assumptions about matters that were highly uncertain at the time the estimate was made, different estimates reasonably could have been used, or the impact of the estimates and assumptions on financial condition or operating performance is material.

Management believes that the accounting estimates employed are appropriate and the resulting balances are reasonable; however, actual results could materially differ from the original estimates, requiring adjustments to these balances in future periods. Management has discussed these critical accounting policies with the Audit Committee, as appropriate. Listed below are the Company's most significant critical accounting estimates and assumptions used in the preparation of the Consolidated Financial Statements.

Income Taxes — We are subject to income taxes in both the U.S. and numerous foreign jurisdictions. Our worldwide income tax provision requires significant judgment and is based on calculations and assumptions that are subject to examination by the Internal Revenue Service and other taxing authorities. Certain of the Company's subsidiaries are under examination by relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each tax jurisdiction when determining the adequacy of the provision for income taxes. Accounting guidance for uncertainty in income taxes prescribes a more likely than not recognition threshold. Tax reserves have been established, which the Company believes to be adequate in relation to the potential for additional assessments. Once established, reserves are adjusted only when there is more information available or when an event occurs necessitating a change to the reserves. While the Company believes that the amounts of the tax estimates are reasonable, it is possible that the ultimate outcome of current or future examinations may be materially different than the reserve amounts.

Because we have a wide range of statutory tax rates in the multiple jurisdictions in which we operate, any changes in our geographical earnings mix could materially impact our effective tax rate. Furthermore, our tax position could be adversely impacted by changes in tax laws, tax treaties or tax regulations or the interpretation or enforcement thereof and such changes may be more likely or become more likely in view of recent economic trends in certain of the jurisdictions in which we operate. As an example, new tax laws were enacted in December 2017 in the U.S. which decreased the statutory income tax rate from 35% to 21%, required a one-time transition tax, and introduced numerous other changes. As further outlined in *Key Trends and Uncertainties*, the Company anticipates that the GILTI provisions of U.S. tax reform could materially impact the effective tax rate in future periods. See Note 21—*Income Taxes* to the Consolidated Financial Statements included in Item 8 of this Form 10-K for additional information.

In accordance with SAB 118, the Company made reasonable estimates of the impacts of U.S. tax reform on its 2017 financial results, and recorded adjustments to those estimates in 2018 as analysis was completed. As of December 31, 2018, our analysis of the one-time impacts of the TCJA is complete under SAB 118. However, in the first quarter of 2019, the U.S. Treasury Department issued final regulations on the one-time transition tax. The final regulations include changes from the proposed regulations issued in 2018 and we expect to record the impacts of the final regulations in the first quarter of 2019. We are still evaluating the final regulations which may have a material impact on our financial statements.

In addition, no taxes have been recorded on undistributed earnings for certain of our non-U.S. subsidiaries to the extent such earnings are considered to be indefinitely reinvested in the operations of those subsidiaries. Should the earnings be remitted as dividends, the Company may be subject to additional foreign withholding and state income taxes.

Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax bases. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The Company has elected to treat GILTI as an expense in the period in which the tax is accrued. Accordingly, no deferred tax assets or liabilities are recorded related to GILTI.

Sales of Noncontrolling Interests — Sales of noncontrolling interests are recognized within stockholders' equity. Effective January 1, 2018, the Company adopted ASU No. 2017-05, *Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets,* which clarified the accounting for the sale of business interests as either the sale of nonfinancial assets or the sale of businesses. Among other things, under the newly adopted guidance fewer transactions are expected to meet the definition of a business under the scope of ASC 810 and will fall under the scope of the sale of nonfinancial assets.

Prior to January 1, 2018, the accounting for a sale of noncontrolling interests was dependent on whether the sale was considered a sale of in-substance real estate, where the gain (loss) on sale would be recognized in earnings rather than within stockholders' equity. In-substance real estate is composed of land plus improvements and integral equipment. The determination of whether property, plant and equipment is integral equipment is based on the significance of the costs to remove the equipment from its existing location (including the cost of repairing damage resulting from the removal), combined with the decrease in the fair value of the equipment as a result of those removal activities. When the combined total of removal costs and the decrease in fair value of the equipment exceeds 10% of the fair value of the equipment, the equipment is considered integral equipment. The accounting standards specifically identify power plants as an example of in-substance real estate. Where the consolidated entity in which noncontrolling interests have been sold contains in-substance real estate, management estimates the extent to which the total fair value of the assets of the entity is represented by the in-substance real estate and whether significant value exists beyond the in-substance real estate. This estimation considers all qualitative and quantitative factors relevant for each sale and, where appropriate, includes making quantitative estimates about the fair value of the entity and its identifiable assets and liabilities (including any favorable or unfavorable contracts) by analogy to the accounting standards on business combinations. As such, these estimates may require significant judgment and assumptions, similar to the critical accounting estimates discussed below for impairments and fair value.

Impairments — Our accounting policies on goodwill and long-lived assets are described in detail in Note 1—*General and Summary of Significant Accounting Policies*, included in Item 8 of this Form 10-K. The Company makes considerable judgments in its impairment evaluations of goodwill and long-lived assets, starting with determining if an impairment indicator exists. Events that may result in an impairment analysis being performed include, but are not limited to: adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, or an expectation it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life. The Company exercises judgment in determining if these events represent an impairment indicator requiring the computation of the fair value of goodwill and/or the recoverability of long-lived assets. The fair value determination is typically the most judgmental part in an impairment evaluation. Please see *Fair Value* below for further detail.

As part of the impairment evaluation process, management analyzes the sensitivity of fair value to various underlying assumptions. The level of scrutiny increases as the gap between fair value and carrying amount decreases. Changes in any of these assumptions could result in management reaching a different conclusion regarding the potential impairment, which could be material. Our impairment evaluations inherently involve uncertainties from uncontrollable events that could positively or negatively impact the anticipated future economic and operating conditions.

Further discussion of the impairment charges recognized by the Company can be found within Note 8—*Goodwill and Other Intangible Assets and* Note 20—*Asset Impairment Expense* to the Consolidated Financial Statements included in Item 8 of this Form 10-K.

Fair Value

Fair Value — For information regarding the fair value hierarchy, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K.

Fair Value of Financial Instruments — A significant number of the Company's financial instruments are carried at fair value with changes in fair value recognized in earnings or other comprehensive income each period. Investments are generally fair valued based on quoted market prices or other observable market data such as interest rate indices. The Company's investments are primarily certificates of deposit and mutual funds. Derivatives are valued using observable data as inputs into internal valuation models. The Company's derivatives primarily consist of interest rate swaps, foreign currency instruments, and commodity and embedded derivatives. Additional discussion regarding the nature of these financial instruments and valuation techniques can be found in Note 4—*Fair Value* included in Item 8 of this Form 10-K.

Fair Value of Nonfinancial Assets and Liabilities — Significant estimates are made in determining the fair value of long-lived tangible and intangible assets (i.e., property, plant and equipment, intangible assets and goodwill) during the impairment evaluation process. In addition, the majority of assets acquired and liabilities assumed in a business combination and asset acquisitions by VIEs are required to be recognized at fair value under the relevant accounting guidance.

The Company may engage an independent valuation firm to assist management with the valuation. The Company generally utilizes the income approach to value nonfinancial assets and liabilities, specifically a Discounted Cash Flow ("DCF") model to estimate fair value by discounting cash flow forecasts, adjusted to reflect market participant assumptions, to the extent necessary, at an appropriate discount rate.

Management applies considerable judgment in selecting several input assumptions during the development of our cash flow forecasts. Examples of the input assumptions that our forecasts are sensitive to include macroeconomic factors such as growth rates, industry demand, inflation, exchange rates, power prices and commodity prices. Whenever appropriate, management obtains these input assumptions from observable market data sources (e.g., Economic Intelligence Unit) and extrapolates the market information if an input assumption is not observable for the entire forecast period. Many of these input assumptions are dependent on other economic assumptions, which are often derived from statistical economic models with inherent limitations such as estimation differences. Further, several input assumptions are based on historical trends which often do not recur. It is not uncommon that different market data sources have different views of the macroeconomic factor expectations and related assumptions. As a result, macroeconomic factors and related assumptions are often available in a narrow range; however, in some situations these ranges become wide and the use of a different set of input assumptions could produce significantly different budgets and cash flow forecasts.

A considerable amount of judgment is also applied in the estimation of the discount rate used in the DCF model. To the extent practical, inputs to the discount rate are obtained from market data sources (e.g., Bloomberg). The Company selects and uses a set of publicly traded companies from the relevant industry to estimate the discount rate inputs. Management applies judgment in the selection of such companies based on its view of the most likely market participants. It is reasonably possible that the selection of a different set of likely market participants could produce different input assumptions and result in the use of a different discount rate.

Accounting for Derivative Instruments and Hedging Activities — We enter into various derivative transactions in order to hedge our exposure to certain market risks. We primarily use derivative instruments to manage our interest rate, commodity and foreign currency exposures. We do not enter into derivative transactions for trading purposes. See Note 5—*Derivative Instruments and Hedging Activities* included in Item 8 of this Form 10-K for further information on the classification.

The fair value measurement standard requires the Company to consider and reflect the assumptions of market participants in the fair value calculation. These factors include nonperformance risk (the risk that the obligation will not be fulfilled) and credit risk, both of the reporting entity (for liabilities) and of the counterparty (for assets). Due to the nature of the Company's interest rate swaps, which are typically associated with non-recourse debt, credit risk for AES is evaluated at the subsidiary level rather than at the Parent Company level. Nonperformance risk on the Company's derivative instruments is an adjustment to the initial asset/liability fair value position that is derived from internally developed valuation models that utilize observable market inputs.

As a result of uncertainty, complexity and judgment, accounting estimates related to derivative accounting could result in material changes to our financial statements under different conditions or utilizing different assumptions. As a part of accounting for these derivatives, we make estimates concerning nonperformance, volatilities, market liquidity, future commodity prices, interest rates, credit ratings (both ours and our counterparty's), and future exchange rates. Refer to Note 4—*Fair Value* included in Item 8 of this Form 10-K for additional details.

The fair value of our derivative portfolio is generally determined using internal and third party valuation models, most of which are based on observable market inputs, including interest rate curves and forward and spot prices for currencies and commodities. The Company derives most of its financial instrument market assumptions from market efficient data sources (e.g., Bloomberg, Reuters and Platt's). In some cases, where market data is not readily available, management uses comparable market sources and empirical evidence to derive market assumptions to determine a financial instrument's fair value. In certain instances, the published curve may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve. Specifically, where there is limited forward curve data with respect to foreign exchange contracts, beyond the traded points the Company utilizes the interest rate differential approach to construct the remaining portion of the forward curve. Additionally, in the absence of quoted prices, we may rely on "indicative pricing" quotes from financial institutions to input into our valuation model for certain of our foreign currency swaps. These indicative pricing quotes do not constitute either a bid or ask price and therefore are not considered observable market data. For individual contracts, the use of different valuation models or assumptions could have a material effect on the calculated fair value.

Regulatory Assets — Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. If future recovery of costs ceases to be probable, any asset write-offs would be required to be recognized in operating income.

Consolidation — The Company enters into transactions impacting the Company's equity interests in its affiliates. In connection with each transaction, the Company must determine whether the transaction impacts the Company's consolidation conclusion by first determining whether the transaction should be evaluated under the variable interest model or the voting model. In determining which consolidation model applies to the transaction, the Company is required to make judgments about how the entity operates, the most significant of which are whether (i) the entity has sufficient equity to finance its activities, (ii) the equity holders, as a group, have the characteristics of a controlling financial interest, and (iii) whether the entity has non-substantive voting rights.

If the entity is determined to be a variable interest entity, the most significant judgment in determining whether the Company must consolidate the entity is whether the Company, including its related parties and de facto agents, collectively have power and benefits. If AES is determined to have power and benefits, the entity will be consolidated by AES.

Alternatively, if the entity is determined to be a voting model entity, the most significant judgments involve determining whether the non-AES shareholders have substantive participating rights. The assessment of shareholder rights and whether they are substantive participating rights requires significant judgment since the rights provided under shareholders' agreements may include selecting, terminating, and setting the compensation of management responsible for implementing the subsidiary's policies and procedures, and establishing operating and capital decisions of the entity, including budgets, in the ordinary course of business. On the other hand, if shareholder rights are only protective in nature (referred to as protective rights) then such rights would not overcome the presumption that the owner of a majority voting interest shall consolidate its investee. Significant judgment is required to determine whether minority rights represent substantive participating rights or protective rights that do not affect the evaluation of control. While both represent an approval or veto right, a distinguishing factor is the underlying activity or action to which the right relates.

Pension and Other Postretirement Plans — The Company recognizes a net asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. The valuation of the Company's benefit obligation, fair value of plan assets, and net periodic benefit costs requires various estimates and assumptions, the most significant of which include the discount rate and expected return on plan assets. These assumptions are reviewed by the Company on an annual basis. Refer to Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for further information.

Revenue Recognition — The Company recognizes revenue to depict the transfer of energy, capacity and other services to customers in an amount that reflects the consideration to which we expect to be entitled. In applying the revenue model, we determine whether the sale of energy, capacity and other services represent a single performance obligation based on the individual market and terms of the contract. Generally, the promise to transfer energy and capacity represent a performance obligation that is satisfied over time and meets the criteria to be accounted for as a series of distinct goods or services. Progress toward satisfaction of a performance obligation is measured using output methods, such as MWhs delivered or MWs made available, and when we are entitled to consideration in an amount that corresponds directly to the value of our performance completed to date, we recognize revenue in the amount to which we have the right to invoice. For further information regarding the nature of our revenue streams and our critical accounting policies affecting revenue recognition, see Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K.

New Accounting Pronouncements — See Note 1—*General and Summary of Significant Accounting Policies* included in Item 8 of this Form 10-K for further information about new accounting pronouncements adopted during 2018 and accounting pronouncements issued, but not yet effective.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Overview Regarding Market Risks — Our businesses are exposed to and proactively manage market risk. Our primary market risk exposure is to the price of commodities, particularly electricity, oil, natural gas, coal and environmental credits. In addition, our businesses are also exposed to lower electricity prices due to increased competition, including from renewable sources such as wind and solar, as a result of lower costs of entry and lower variable costs. We operate in multiple countries and as such are subject to volatility in exchange rates at varying degrees at the subsidiary level and between our functional currency, the U.S. dollar, and currencies of the countries in which we operate. We are also exposed to interest rate fluctuations due to our issuance of debt and related financial instruments.

The disclosures presented in this Item 7A are based upon a number of assumptions; actual effects may differ. The safe harbor provided in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 shall apply to the disclosures contained in this Item 7A. For further information regarding market risk, see Item 1A.—*Risk Factors*, *Our financial position and results of operations may fluctuate significantly due to fluctuations in currency exchange rates experienced at our foreign operations*, *Wholesale power prices are declining in many markets and this could have a material adverse effect on our operations and opportunities for future growth,* and *We may not be adequately hedged against our exposure to changes in commodity prices or interest rates* of this 2018 Form 10-K.

Commodity Price Risk — Although we prefer to hedge our exposure to the impact of market fluctuations in the price of electricity, fuels and environmental credits, some of our generation businesses operate under short-term sales or under contract sales that leave an unhedged exposure on some of our capacity or through imperfect fuel pass-throughs. In our utility businesses, we may be exposed to commodity price movements depending on our excess or shortfall of generation relative to load obligations and sharing or pass-through mechanisms. These businesses subject our operational results to the volatility of prices for electricity, fuels and environmental credits in competitive markets. We employ risk management strategies to hedge our financial performance against the effects of fluctuations in energy commodity prices. The implementation of these strategies can involve the use of physical and financial commodity contracts, futures, swaps and options.

The portion of our sales and purchases that are not subject to such agreements or contracted businesses where indexation is not perfectly matched to business drivers will be exposed to commodity price risk. When hedging the output of our generation assets, we utilize contract sales that lock in the spread per MWh between variable costs and the price at which the electricity can be sold.

AES businesses will see changes in variable margin performance as global commodity prices shift. For 2019, we project pre-tax earnings exposure on a 10% move in commodity prices would be approximately less than $5 million for U.S. power, $(10) million for natural gas, less than $(5) million for oil and $(5) million for coal. Our estimates exclude correlation of oil with coal or natural gas. For example, a decline in oil or natural gas prices can be accompanied by a decline in coal price if commodity prices are correlated. In aggregate, the Company's downside exposure occurs with lower power, higher oil, higher natural gas, and higher coal prices. Exposures at individual businesses will change as new contracts or financial hedges are executed, and our sensitivity to changes in commodity prices generally increases in later years with reduced hedge levels at some of our businesses.

Commodity prices affect our businesses differently depending on the local market characteristics and risk management strategies. Spot power prices, contract indexation provisions and generation costs can be directly or indirectly affected by movements in the price of natural gas, oil and coal. We have some natural offsets across our businesses such that low commodity prices may benefit certain businesses and be a cost to others. Exposures are not perfectly linear or symmetric. The sensitivities are affected by a number of local or indirect market factors. Examples of these factors include hydrology, local energy market supply/demand balances, regional fuel supply issues, regional competition, bidding strategies and regulatory interventions such as price caps. Operational flexibility changes the shape of our sensitivities. For instance, certain power plants may limit downside exposure by reducing dispatch in low market environments. Volume variation also affects our commodity exposure. The volume sold under contracts or retail concessions can vary based on weather and economic conditions resulting in a higher or lower volume of sales in spot markets. Thermal unit availability and hydrology can affect the generation output available for sale and can affect the marginal unit setting power prices.

In the US and Utilities SBU, the generation businesses are largely contracted but may have residual risk to the extent contracts are not perfectly indexed to the business drivers. IPL primarily generates energy to meet its retail customer demand; however, it opportunistically sells surplus economic energy into wholesale markets at market prices.

In the South America SBU, our business in Chile owns assets in the central and northern regions of the country and has a portfolio of contract sales in both. In the central region, the contract sales generally cover the efficient generation from our coal-fired and hydroelectric assets. Any residual spot price risk will primarily be driven by the amount of hydrological inflows. In the case of low hydroelectric generation, spot price exposure is capped by the ability to dispatch our natural gas/diesel assets, the price of which depends on fuel pricing at the time required. There is a small amount of coal generation in the northern region that is not covered by the portfolio of contract sales and therefore subject to spot price risk. In both regions, under normal hydrology conditions, coal-firing generation sets the price. However, when there are spikes in price due to lower hydrology and higher demand, gas or oil-linked fuels generally set power prices. In Colombia, we operate under a short-term sales strategy and have commodity exposure to unhedged volumes. Because we own hydroelectric assets there, contracts are not indexed to fuel. Additionally, in Brazil, the hydroelectric generating facility is covered by contract sales. Under normal hydrological volatility, spot price risk is mitigated through a regulated sharing mechanism across all hydroelectric generators in the country. Under drier conditions, the sharing mechanism may not be sufficient to cover the business' contract position, and therefore it may have to purchase power at spot prices driven by the cost of thermal generation.

In the MCAC SBU, our businesses have commodity exposure on unhedged volumes. Panama is highly contracted under a portfolio of fixed volume contract sales. To the extent hydrological inflows are greater than or less than the contract sales volume, the business will be sensitive to changes in spot power prices which may be driven by oil prices in some time periods. In Dominican Republic, we own natural gas-fired assets contracted under a portfolio of contract sales and a coal-fired asset contracted with a single contract, and both contract and spot prices may move with commodity prices. Additionally, the contract levels do not always match our generation availability and our assets may be sellers of spot prices in excess of contract levels or a net buyer in the spot market to satisfy contract obligations.

In the Eurasia SBU, our Kilroot facility operates on a short-term sales strategy. To the extent that variable energy margin is unhedged, the commodity risk at our Kilroot business is to the clean dark spread, which is the difference between electricity price and our coal-based variable dispatch cost, including emissions. Natural gas-fired generators set power prices for many periods, so higher natural gas prices generally expand margins and higher coal or emissions prices reduce them. Similarly, increased wind generators displace higher cost generation, potentially reducing Kilroot's margins, and vice versa. Two steam gas generating units at Ballylumford were shut down at the end of 2018 having reached the end of their economic lives. The open cycle gas turbines at both Ballylumford and Kilroot will continue to operate as peaking units at times of high demand. Our Mong Duong business has minimal exposure to commodity price risk as it has no merchant exposure and fuel is subject to a pass-through mechanism.

Foreign Exchange Rate Risk — In the normal course of business, we are exposed to foreign currency risk and other foreign operations risks that arise from investments in foreign subsidiaries and affiliates. A key component of these risks stems from the fact that some of our foreign subsidiaries and affiliates utilize currencies other than our consolidated reporting currency, the USD. Additionally, certain of our foreign subsidiaries and affiliates have entered into monetary obligations in USD or currencies other than their own functional currencies. We have varying degrees of exposure to changes in the exchange rate between the USD and the following currencies: Argentine peso, British pound, Brazilian real, Chilean peso, Colombian peso, Dominican peso, Euro, Indian rupee, and Mexican peso. These subsidiaries and affiliates have attempted to limit potential foreign exchange exposure by entering into revenue contracts that adjust to changes in foreign exchange rates. We also use foreign currency forwards, swaps and options, where possible, to manage our risk related to certain foreign currency fluctuations.

AES enters into foreign currency hedges to protect economic value of the business and minimize impact of foreign exchange rate fluctuations to AES' portfolio. While protecting cash flows, the hedging strategy is also designed to reduce forward-looking earnings foreign exchange volatility. Due to variation of timing and amount between cash distribution and earnings exposure, the hedge impact may not fully cover the earnings exposure on a realized basis, which could result in greater volatility in earnings. The largest foreign exchange risks over a 12-month forward-looking period stem from the following currencies: Argentine peso, Brazilian real, Colombian peso, Euro, British pound, and Indian Rupee. As of December 31, 2018, assuming a 10% USD appreciation, cash distributions attributable to foreign subsidiaries exposed to movement in the exchange rate of the Argentine peso and Euro each are projected to be reduced by $5 million, and the Colombian peso, Brazilian real, British pound and Indian Rupee each are projected to be impacted by less than $5 million. These numbers have been produced by applying a one-time 10% USD appreciation to forecasted exposed cash distributions for 2019 coming from the respective subsidiaries exposed to the currencies listed above, net of the impact of outstanding hedges and holding all other variables constant. The numbers presented above are net of any transactional gains/losses. These sensitivities may change in the future as new hedges are executed or existing hedges are unwound. Additionally, updates to the forecasted cash distributions exposed to foreign exchange risk may result in further modification. The sensitivities presented do not capture the impacts of any administrative market restrictions or currency inconvertibility.

Interest Rate Risks — We are exposed to risk resulting from changes in interest rates as a result of our issuance of variable and fixed-rate debt, as well as interest rate swap, cap, floor and option agreements.

Decisions on the fixed-floating debt mix are made to be consistent with the risk factors faced by individual businesses or plants. Depending on whether a plant's capacity payments or revenue stream is fixed or varies with inflation, we partially hedge against interest rate fluctuations by arranging fixed-rate or variable-rate financing. In certain cases, particularly for non-recourse financing, we execute interest rate swap, cap and floor agreements to effectively fix or limit the interest rate exposure on the underlying financing. Most of our interest rate risk is related to non-recourse financings at our businesses.

As of December 31, 2018, the portfolio's pre-tax earnings exposure for 2019 to a one-time 100-basis-point increase in interest rates for our Argentine peso, Brazilian real, Chilean peso, Colombian peso, Euro and USD denominated debt would be approximately $20 million on interest expense for the debt denominated in these currencies. These amounts do not take into account the historical correlation between these interest rates.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of The AES Corporation:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of The AES Corporation (the Company) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2019, expressed an unqualified opinion thereon.

Adoption of New Accounting Standards

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for revenue as a result of the adoption of Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), and the amendments in ASUs 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-10 and 2017-13 effective January 1, 2018.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2008.

Tysons, Virginia
February 26, 2019

THE AES CORPORATION

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2018 AND 2017

	2018	2017
	(in millions, except share and per share data)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,166	$ 949
Restricted cash	370	274
Short-term investments	313	424
Accounts receivable, net of allowance for doubtful accounts of $23 and $10, respectively	1,595	1,463
Inventory	577	562
Prepaid expenses	130	62
Other current assets	807	630
Current assets of discontinued operations and held-for-sale businesses	57	2,034
Total current assets	5,015	6,398
NONCURRENT ASSETS		
Property, Plant and Equipment:		
Land	449	502
Electric generation, distribution assets and other	25,242	24,119
Accumulated depreciation	(8,227)	(7,942)
Construction in progress	3,932	3,617
Property, plant and equipment, net	21,396	20,296
Other Assets:		
Investments in and advances to affiliates	1,114	1,197
Debt service reserves and other deposits	467	565
Goodwill	1,059	1,059
Other intangible assets, net of accumulated amortization of $457 and $441, respectively	436	366
Deferred income taxes	97	130
Service concession assets, net of accumulated amortization of $0 and $206, respectively	—	1,360
Loan receivable	1,423	—
Other noncurrent assets	1,514	1,741
Total other assets	6,110	6,418
TOTAL ASSETS	$ 32,521	$ 33,112
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 1,329	$ 1,371
Accrued interest	191	228
Accrued non-income taxes	250	252
Accrued and other liabilities	962	980
Non-recourse debt, including $479 and $1,012, respectively, related to variable interest entities	1,659	2,164
Current liabilities of discontinued operations and held-for-sale businesses	8	1,033
Total current liabilities	4,399	6,028
NONCURRENT LIABILITIES		
Recourse debt	3,650	4,625
Non-recourse debt, including $2,922 and $1,358 respectively, related to variable interest entities	13,986	13,176
Deferred income taxes	1,280	1,006
Other noncurrent liabilities	2,723	2,595
Total noncurrent liabilities	21,639	21,402
Commitments and Contingencies (see Notes 11 and 12)		
Redeemable stock of subsidiaries	879	837
EQUITY		
THE AES CORPORATION STOCKHOLDERS' EQUITY		
Common stock ($0.01 par value, 1,200,000,000 shares authorized; 817,203,691 issued and 662,298,096 outstanding at December 31, 2018 and 816,312,913 issued and 660,388,128 outstanding at December 31, 2017)	8	8
Additional paid-in capital	8,154	8,501
Accumulated deficit	(1,005)	(2,276)
Accumulated other comprehensive loss	(2,071)	(1,876)
Treasury stock, at cost (154,905,595 and 155,924,785 shares at December 31, 2018 and 2017, respectively)	(1,878)	(1,892)
Total AES Corporation stockholders' equity	3,208	2,465
NONCONTROLLING INTERESTS	2,396	2,380
Total equity	5,604	4,845
TOTAL LIABILITIES AND EQUITY	$ 32,521	$ 33,112

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	2018	2017	2016
	(in millions, except per share amounts)		
Revenue:			
Regulated	$ 2,939	$ 3,109	$ 3,310
Non-Regulated	7,797	7,421	6,971
Total revenue	10,736	10,530	10,281
Cost of Sales:			
Regulated	(2,473)	(2,650)	(2,839)
Non-Regulated	(5,690)	(5,415)	(5,059)
Total cost of sales	(8,163)	(8,065)	(7,898)
Operating margin	2,573	2,465	2,383
General and administrative expenses	(192)	(215)	(194)
Interest expense	(1,056)	(1,170)	(1,134)
Interest income	310	244	245
Loss on extinguishment of debt	(188)	(68)	(13)
Other expense	(58)	(58)	(80)
Other income	72	120	64
Gain (loss) on disposal and sale of business interests	984	(52)	29
Asset impairment expense	(208)	(537)	(1,096)
Foreign currency transaction gains (losses)	(72)	42	(15)
Other non-operating expense	(147)	—	(2)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES AND EQUITY IN EARNINGS OF AFFILIATES	2,018	771	187
Income tax expense	(708)	(990)	(32)
Net equity in earnings of affiliates	39	71	36
INCOME (LOSS) FROM CONTINUING OPERATIONS	1,349	(148)	191
Income (loss) from operations of discontinued businesses, net of income tax benefit (expense) of $(2), $(21), and $229, respectively	(9)	(18)	151
Gain (loss) from disposal and impairments of discontinued businesses, net of income tax benefit (expense) of $(44), $0, and $266, respectively	225	(611)	(1,119)
NET INCOME (LOSS)	1,565	(777)	(777)
Noncontrolling interests:			
Less: Income from continuing operations attributable to noncontrolling interests and redeemable stock of subsidiaries	(364)	(359)	(211)
Less: Loss (income) from discontinued operations attributable to noncontrolling interests	2	(25)	(142)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 1,203	$ (1,161)	$ (1,130)
AMOUNTS ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS:			
Income (loss) from continuing operations, net of tax	$ 985	$ (507)	$ (20)
Income (loss) from discontinued operations, net of tax	218	(654)	(1,110)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 1,203	$ (1,161)	$ (1,130)
BASIC EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.49	$ (0.77)	$ (0.04)
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.33	(0.99)	(1.68)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 1.82	$ (1.76)	$ (1.72)
DILUTED EARNINGS PER SHARE:			
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.48	$ (0.77)	$ (0.04)
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	0.33	(0.99)	(1.68)
NET INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION COMMON STOCKHOLDERS	$ 1.81	$ (1.76)	$ (1.72)
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.53	$ 0.49	$ 0.45

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	2018	2017	2016
		(in millions)	
NET INCOME (LOSS)	$ 1,565	$ (777)	$ (777)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax benefit of $2, $17, and $1, respectively	(161)	(9)	189
Reclassification to earnings, net of $0 income tax for all periods	(21)	643	992
Total foreign currency translation adjustments	(182)	634	1,181
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $27, $10 and $(7), respectively	(67)	(12)	5
Reclassification to earnings, net of income tax expense of $24, $1 and $8, respectively	93	50	37
Total change in fair value of derivatives	26	38	42
Pension activity:			
Change in pension adjustments due to prior service cost, net of income tax benefit (expense) of $1, $(1), and $(6) respectively	(2)	2	11
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax benefit of $1, $6, and $106, respectively	(1)	(21)	(208)
Reclassification to earnings, net of income tax expense of $2, $135, and $3 respectively	8	266	10
Total pension adjustments	5	247	(187)
OTHER COMPREHENSIVE INCOME (LOSS)	(151)	919	1,036
COMPREHENSIVE INCOME	1,414	142	259
Less: Comprehensive income attributable to noncontrolling interests	(425)	(390)	(262)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO THE AES CORPORATION	$ 989	$ (248)	$ (3)

See Accompanying Notes to Consolidated Financial Statements.

THE AES CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	THE AES CORPORATION STOCKHOLDERS							
	Common Stock		Treasury Stock					
(in millions)	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Loss	Noncontrolling Interests
Balance at December 31, 2015	815.8	$ 8	149.0	$ (1,837)	$ 8,718	$ 143	$ (3,883)	$ 3,022
Net income (loss)	—	—	—	—	—	(1,130)	—	353
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	1,109	72
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	30	12
Total pension adjustments, net of income tax	—	—	—	—	—	—	(12)	(175)
Total other comprehensive income (loss)	—	—	—	—	—	—	1,127	(91)
Fair value adjustment [(1)]	—	—	—	—	17	(4)	—	(17)
Disposition of business interests [(2)]	—	—	—	—	—	—	—	(2)
Distributions to noncontrolling interests	—	—	—	—	(10)	—	—	(430)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	60
Dividends declared on common stock	—	—	—	—	(226)	(71)	—	—
Purchase of treasury stock	—	—	8.7	(79)	—	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	0.3	—	(0.8)	12	11	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	84	(84)	—	17
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	(2)	—	—	(17)
Less: Net loss attributable to redeemable stock of subsidiaries	—	—	—	—	—	—	—	11
Balance at December 31, 2016	816.1	$ 8	156.9	$ (1,904)	$ 8,592	$ (1,146)	$ (2,756)	$ 2,906
Net income (loss)	—	—	—	—	—	(1,161)	—	384
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	661	(27)
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	23	15
Total pension adjustments, net of income tax	—	—	—	—	—	—	229	18
Total other comprehensive income	—	—	—	—	—	—	913	6
Cumulative effect of a change in accounting principle [(3)]	—	—	—	—	—	31	—	—
Fair value adjustment [(1)]	—	—	—	—	(25)	—	—	—
Disposition of business interests [(2)]	—	—	—	—	—	—	—	(666)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(426)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	11
Dividends declared on common stock	—	—	—	—	(324)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	0.2	—	(1.0)	12	5	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	13	—	7	83
Acquisition of subsidiary shares from noncontrolling interests	—	—	—	—	240	—	(40)	68
Less: Net loss attributable to redeemable stock of subsidiaries	—	—	—	—	—	—	—	14
Balance at December 31, 2017	816.3	$ 8	155.9	$ (1,892)	$ 8,501	$ (2,276)	$ (1,876)	$ 2,380
Net income	—	—	—	—	—	1,203	—	360
Total foreign currency translation adjustment, net of income tax	—	—	—	—	—	—	(235)	53
Total change in derivative fair value, net of income tax	—	—	—	—	—	—	14	10
Total pension adjustments, net of income tax	—	—	—	—	—	—	7	(2)
Total other comprehensive income (loss)	—	—	—	—	—	—	(214)	61
Cumulative effect of a change in accounting principle [(3)]	—	—	—	—	—	68	19	81
Fair value adjustment [(1)]	—	—	—	—	(4)	—	—	—
Disposition of business interests [(2)]	—	—	—	—	—	—	—	(250)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(343)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	9
Dividends declared on common stock	—	—	—	—	(348)	—	—	—
Issuance and exercise of stock-based compensation benefit plans, net of income tax	0.9	—	(1.0)	14	8	—	—	—
Sale of subsidiary shares to noncontrolling interests	—	—	—	—	(3)	—	—	98
Balance at December 31, 2018	817.2	$ 8	154.9	$ (1,878)	$ 8,154	$ (1,005)	$ (2,071)	$ 2,396

(1) Adjustment to the carrying amount of noncontrolling interest and redeemable stock of subsidiaries to fair value.

(2) See Note 23—*Held-for-Sale and Dispositions* for further information.

(3) See Note 1—*General and Summary of Significant Accounting Policies* for further information.

See Accompanying Notes to Consolidated Financial Statements

THE AES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	2018	2017	2016
		(in millions)	
OPERATING ACTIVITIES:			
Net income (loss)	$ 1,565	$ (777)	$ (777)
Adjustments to net income (loss):			
Depreciation and amortization	1,003	1,169	1,176
Loss (gain) on disposal and sale of business interests	(984)	52	(29)
Impairment expenses	355	537	1,098
Deferred income taxes	313	672	(793)
Provisions for contingencies	14	34	48
Loss on extinguishment of debt	188	68	20
Loss on sale and disposal of assets	27	43	38
Net loss (gain) from disposal and impairments of discontinued businesses	(269)	611	1,383
Other	317	160	180
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable	(206)	(177)	237
(Increase) decrease in inventory	(36)	(28)	42
(Increase) decrease in prepaid expenses and other current assets	(22)	107	870
(Increase) decrease in other assets	(32)	(295)	(251)
Increase (decrease) in accounts payable and other current liabilities	62	163	(619)
Increase (decrease) in income tax payables, net and other tax payables	(7)	53	(199)
Increase (decrease) in other liabilities	55	112	473
Net cash provided by operating activities	2,343	2,504	2,897
INVESTING ACTIVITIES:			
Capital expenditures	(2,121)	(2,177)	(2,345)
Acquisitions of business interests, net of cash and restricted cash acquired	(66)	(609)	(52)
Proceeds from the sale of business interests, net of cash and restricted cash sold	2,020	108	538
Sale of short-term investments	1,302	3,540	4,904
Purchase of short-term investments	(1,411)	(3,310)	(5,151)
Contributions to equity investments	(145)	(89)	(6)
Other investing	(84)	(62)	(24)
Net cash used in investing activities	(505)	(2,599)	(2,136)
FINANCING ACTIVITIES:			
Borrowings under the revolving credit facilities	1,865	2,156	1,465
Repayments under the revolving credit facilities	(2,238)	(1,742)	(1,433)
Issuance of recourse debt	1,000	1,025	500
Repayments of recourse debt	(1,933)	(1,353)	(808)
Issuance of non-recourse debt	1,928	3,222	2,978
Repayments of non-recourse debt	(1,411)	(2,360)	(2,666)
Payments for financing fees	(39)	(100)	(105)
Distributions to noncontrolling interests	(340)	(424)	(476)
Contributions from noncontrolling interests and redeemable security holders	43	73	190
Proceeds from the sale of redeemable stock of subsidiaries	—	—	134
Dividends paid on AES common stock	(344)	(317)	(290)
Payments for financed capital expenditures	(275)	(179)	(113)
Purchase of treasury stock	—	—	(79)
Proceeds from sales to noncontrolling interests, net of transaction costs	—	94	—
Other financing	101	(52)	(44)
Net cash provided by (used in) financing activities	(1,643)	43	(747)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	(54)	8	37
(Increase) decrease in cash, cash equivalents and restricted cash of discontinued operations and held-for-sale businesses	74	(128)	(42)
Total increase (decrease) in cash, cash equivalents and restricted cash	215	(172)	9
Cash, cash equivalents and restricted cash, beginning	1,788	1,960	1,951
Cash, cash equivalents and restricted cash, ending	$ 2,003	$ 1,788	$ 1,960
SUPPLEMENTAL DISCLOSURES:			
Cash payments for interest, net of amounts capitalized	$ 1,003	$ 1,196	$ 1,273
Cash payments for income taxes, net of refunds	370	377	487
SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES:			
Non-cash acquisition of intangible assets	16	—	—
Non-cash contributions of assets and liabilities for the Fluence transaction (see Note 7)	20	—	—
Non-cash exchange of debentures for the acquisition of the Guaimbê Solar Complex (see Note 24)	119	—	—
Non-cash acquisition of the remaining interest in a Distributed Energy equity affiliate (see Note 24)	23	—	—
Dividends declared but not yet paid	90	86	174
Conversion of Alto Maipo loans and accounts payable into equity (see Note 14)	—	279	—
Return Share Transfer Payment due (see Note 23)	—	75	—

See Accompanying Notes to Consolidated Financial Statements

1. GENERAL AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The AES Corporation is a holding company (the "Parent Company") that, through its subsidiaries and affiliates, (collectively, "AES" or "the Company") operates a geographically diversified portfolio of electricity generation and distribution businesses. Generally, the liabilities of individual operating entities are non-recourse to the Parent Company and are isolated to the operating entities. Most of our operating entities are structured as limited liability entities, which limit the liability of shareholders. The structure is generally the same regardless of whether a subsidiary is consolidated under a voting or variable interest model. The preparation of these consolidated financial statements is in conformity with accounting principles generally accepted in the United States of America ("US GAAP").

PRINCIPLES OF CONSOLIDATION — The consolidated financial statements of the Company include the accounts of The AES Corporation and its controlled subsidiaries. Furthermore, VIEs in which the Company has an ownership interest and is the primary beneficiary, thus controlling the VIE, have been consolidated. Intercompany transactions and balances are eliminated in consolidation. Investments in entities where the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting.

NONCONTROLLING INTERESTS — Noncontrolling interests are classified as a separate component of equity in the Consolidated Balance Sheets and Consolidated Statements of Changes in Equity. Additionally, net income and comprehensive income attributable to noncontrolling interests are reflected separately from consolidated net income and comprehensive income on the Consolidated Statements of Operations and Consolidated Statements of Changes in Equity. Any change in ownership of a subsidiary while the controlling financial interest is retained is accounted for as an equity transaction between the controlling and noncontrolling interests (unless the transaction qualified as a sale of in-substance real estate). Losses continue to be attributed to the noncontrolling interests, even when the noncontrolling interests' basis has been reduced to zero.

Equity securities with redemption features that are not solely within the control of the issuer are classified outside of permanent equity. Generally, initial measurement will be at fair value. Subsequent measurement and classification vary depending on whether the instrument is probable of becoming redeemable. When the equity instrument is not probable of becoming redeemable, subsequent allocation of income and dividends is classified in permanent equity. For those securities where it is probable that the instrument will become redeemable or that are currently redeemable, AES recognizes changes in the fair value at each accounting period against retained earnings or additional paid-in-capital in the absence of retained earnings, subject to the floor of the initial fair value. Further, the allocation of income and dividends, as well as the adjustment to fair value, is classified outside permanent equity. Instruments that are mandatorily redeemable are classified as a liability.

EQUITY METHOD INVESTMENTS — Investments in entities over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method of accounting and reported in *Investments in and advances to affiliates* on the Consolidated Balance Sheets. The Company’s proportionate share of the net income or loss of these companies is included in our results of operations.

The Company utilizes the cumulative earning approach to determine whether distributions received from equity method investees are returns on investment or returns of investment. The Company discontinues the application of the equity method when an investment is reduced to zero and the Company is not otherwise committed to provide further financial support to the investee. The Company resumes the application of the equity method accounting to the extent that net income is greater than the share of net losses not previously recorded.

Upon acquiring the investment, we determine the fair value of the identifiable assets and assumed liabilities and the basis difference between each fair value and the carrying amount of the corresponding asset or liability in the financial statements of the investee. The AES share of the amortization of the basis difference is recognized in *Net equity in earnings of affiliates* in the Consolidated Statements of Operations over the life of the asset or liability.

The Company periodically assesses if impairment indicators exist at our equity method investments. When an impairment is observed, any excess of the carrying amount over its estimated fair value is recognized as impairment expense when the loss in value is deemed other-than-temporary and included in *Other non-operating expense* in the Consolidated Statements of Operations.

BUSINESS INTERESTS — Acquisitions and disposals of business interests are generally transactions pertaining to legal entities, which may be accounted for as a consolidated business, an asset, or an equity method investment. Losses on sales of business interests are limited to the impairment of long-lived assets as of the date of execution of the sales agreement. Any additional gains/(losses) on sales are recognized in *Gain (loss) on disposal and sale of business interests* in the Consolidated Statement of Operations upon completion of the sale.

ALLOCATION OF EARNINGS — Certain of the Company's businesses are subject to profit-sharing arrangements where the allocation of cash distributions and the sharing of tax benefits are not based on fixed ownership percentages. These arrangements exist for certain U.S. renewable generation partnerships to designate different allocations of value among investors, where the allocations change in form or percentage over the life of the partnership. For these businesses, the Company uses the hypothetical liquidation at book value ("HLBV") method when it is a reasonable approximation of the profit-sharing arrangement. The HLBV method calculates the proceeds that would be attributable to each partner based on the liquidation provisions of the respective operating partnership agreement if the partnership was to be liquidated at book value at the balance sheet date. Each partner's share of income in the period is equal to the change in the amount of net equity they are legally able to claim based on a hypothetical liquidation of the entity at the end of a reporting period compared to the beginning of that period, adjusted for any capital transactions.

The HLBV method is used both to allocate the equity earnings attributable to AES when the Company accounts for the renewable business as an equity method investment and to calculate the earnings attributable to noncontrolling interest when the business is consolidated by AES. Where, prior to the commencement of operating activities for a respective renewable energy facility, HLBV results in an immediate decrease in the hypothetical liquidation proceeds attributable to the tax equity investor due to the recognition of ITCs or other adjustments as required by the U.S. Internal Revenue Code, the Company records the impact (sometimes referred to as the 'Day one gain') to income in the same period.

USE OF ESTIMATES — US GAAP requires the Company to make estimates and assumptions that affect the asset and liability balances reported as of the date of the consolidated financial statements, as well as the revenues and expenses recognized during the reporting period. Actual results could differ from those estimates. Items subject to such estimates and assumptions include: the carrying amount and estimated useful lives of long-lived assets; asset retirement obligations; impairment of goodwill, long-lived assets and equity method investments; valuation allowances for receivables and deferred tax assets; the recoverability of regulatory assets; regulatory liabilities; the fair value of financial instruments; the fair value of assets and liabilities acquired as business combinations or as asset acquisitions by variable interest entities; the measurement of equity method investments or noncontrolling interest using the HLBV method for certain renewable generation partnerships; the determination of whether a sale of noncontrolling interests is considered to be a sale of in-substance real estate (as opposed to an equity transaction); pension liabilities; environmental liabilities; the impact of U.S. tax reform; and potential litigation claims and settlements.

HELD-FOR-SALE DISPOSAL GROUPS— A disposal group classified as held-for-sale is reflected on the balance sheet at the lower of its carrying amount or estimated fair value less cost to sell. A loss is recognized if the carrying amount of the disposal group exceeds its estimated fair value less cost to sell. This loss is limited to the carrying value of long-lived assets until the completion of the sale, at which point, any additional loss is recognized. If the fair value of the disposal group subsequently exceeds the carrying amount while the disposal group is still held-for-sale, any impairment expense previously recognized will be reversed up to the lesser of the previously recognized expense or the subsequent excess.

Assets and liabilities related to a disposal group classified as held-for-sale are segregated in the current balance sheet in the period in which the disposal group is classified as held-for-sale. Assets and liabilities of held-for-sale disposal groups are classified as current when they are expected to be disposed of within twelve months. Transactions between the held-for-sale disposal group and businesses that are expected to continue to exist after the disposal are not eliminated to appropriately reflect the continuing operations and balances held-for-sale. See Note 23—*Held-for-Sale and Dispositions* for further information.

DISCONTINUED OPERATIONS — Discontinued operations reporting occurs only when the disposal of a business or a group of businesses represents a strategic shift that has (or will have) a major effect on the Company's operations and financial results. The Company reports financial results for discontinued operations separately from continuing operations to distinguish the financial impact of disposal transactions from ongoing operations. Prior period amounts in the Consolidated Statements of Operations and Consolidated Balance Sheets are retrospectively revised to reflect the businesses determined to be discontinued operations. The cash flows of businesses that are determined to be discontinued operations are included within the relevant categories within operating, investing and financing activities on the face of the Consolidated Statements of Cash Flows.

Transactions between the businesses determined to be discontinued operations and businesses that are expected to continue to exist after the disposal are not eliminated to appropriately reflect the continuing operations and balances held-for-sale. The results of discontinued operations include any gain or loss recognized on closing or adjustment of the carrying amount to fair value less cost to sell, including gains or losses associated with noncontrolling interests upon completion of the disposal transaction. Adjustments related to components previously reported as discontinued operations under prior accounting guidance are presented as discontinued operations in the current period even if the disposed-of component to which the adjustments are related would not meet the criteria for presentation as a discontinued operation under current guidance. See Note 22—*Discontinued Operations* for further information.

FAIR VALUE — Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly, hypothetical transaction between market participants at the measurement date, or exit price. The Company applies the fair value measurement accounting guidance to financial assets and liabilities in determining the fair value of investments in marketable debt and equity securities, included in the Consolidated Balance Sheet line items *Short-term investments* and *Other noncurrent assets*; derivative assets, included in *Other current assets* and *Other noncurrent assets*; and, derivative liabilities, included in *Accrued and other liabilities (current)* and *Other noncurrent liabilities*. The Company applies the fair value measurement guidance to nonfinancial assets and liabilities upon the acquisition of a business or an asset acquisition by a variable interest entity, or in conjunction with the measurement of an asset retirement obligation or a potential impairment loss on an asset group or goodwill.

When determining the fair value measurements for assets and liabilities required to be reflected at their fair values, the Company considers the principal or most advantageous market in which it would transact and considers assumptions that market participants would use when pricing the assets or liabilities, such as inherent risk, transfer restrictions and risk of nonperformance. The Company is prohibited from including transaction costs and any adjustments for blockage factors in determining fair value.

In determining fair value measurements, the Company maximizes the use of observable inputs and minimizes the use of unobservable inputs. Assets and liabilities are categorized within a fair value hierarchy based upon the lowest level of input that is significant to the fair value measurement:

- Level 1: Quoted prices in active markets for identical assets or liabilities;
- Level 2: Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in markets that are not active or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities; or
- Level 3: Unobservable inputs that are supported by little or no market activity and that are significant to the fair values of the assets or liabilities.

Any transfers between all levels within the fair value hierarchy levels are recognized at the end of the reporting period.

CASH AND CASH EQUIVALENTS — The Company considers unrestricted cash on hand, cash balances not restricted as to withdrawal or usage, deposits in banks, certificates of deposit and short-term marketable securities with original maturities of three months or less to be cash and cash equivalents.

RESTRICTED CASH AND DEBT SERVICE RESERVES — Cash balances restricted as to withdrawal or usage, primarily via contract, are considered restricted cash.

The following table provides a summary of cash, cash equivalents, and restricted cash amounts reported on the Consolidated Balance Sheets that reconcile to the total of such amounts as shown on the Consolidated Statements of Cash Flows (in millions):

	December 31, 2018	December 31, 2017
Cash and cash equivalents	$ 1,166	$ 949
Restricted cash	370	274
Debt service reserves and other deposits	467	565
Cash, Cash Equivalents and Restricted Cash	**$ 2,003**	**$ 1,788**

INVESTMENTS IN MARKETABLE SECURITIES — The Company's marketable investments are primarily unsecured debentures, certificates of deposit, government debt securities and money market funds.

Short-term investments consist of marketable equity securities and debt securities with original maturities in excess of three months with remaining maturities of less than one year. Marketable debt securities where the Company has both the positive intent and ability to hold to maturity are classified as held-to-maturity and are carried at amortized cost. Remaining marketable debt securities are classified as available-for-sale or trading and are carried at fair value.

Unrealized gains or losses on available-for-sale debt securities are reflected in AOCL, a separate component of equity, and the Consolidated Statements of Operations, respectively. Unrealized gains or losses on equity investments are reported in *Other income*. Interest and dividends on investments are reported in *Interest income* and *Other income*, respectively. Gains and losses on sales of investments are determined using the specific identification method.

ACCOUNTS AND NOTES RECEIVABLE AND ALLOWANCE FOR DOUBTFUL ACCOUNTS — Accounts and notes receivable are carried at amortized cost. The Company periodically assesses the collectability of accounts receivable, considering factors such as historical collection experience, the age of accounts receivable and other currently available evidence supporting collectability, and records an allowance for doubtful accounts for the estimated uncollectible amount as appropriate. Certain of our businesses charge interest on accounts receivable. Interest income is recognized on an accrual basis. When collection of such interest is not reasonably assured, interest income is recognized as cash is received. Individual accounts and notes receivable are written off when they are no longer deemed collectible.

INVENTORY — Inventory primarily consists of fuel and other raw materials used to generate power, and operational spare parts and supplies used to maintain power generation and distribution facilities. Inventory is carried at lower of cost or net realizable value. Cost is the sum of the purchase price and expenditures incurred to bring the inventory to its existing location. Inventory is primarily valued using the average cost method. Generally, if it is expected fuel inventory will not be recovered through revenue earned from power generation, an impairment is recognized to reflect the fuel at market value. The carrying amount of spare parts and supplies is typically reduced only in instances where the items are considered obsolete.

LONG-LIVED ASSETS — Long-lived assets include property, plant and equipment, assets under capital leases and intangible assets subject to amortization (i.e., finite-lived intangible assets).

Property, plant and equipment — Property, plant and equipment are stated at cost, net of accumulated depreciation. The cost of renewals and improvements that extend the useful life of property, plant and equipment are capitalized.

Construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction in progress are capitalized during the construction period, provided the completion of the construction project is deemed probable, or expensed at the time construction completion is determined to no longer be probable. The continued capitalization of such costs is subject to risks related to successful completion, including those related to government approvals, site identification, financing, construction permitting and contract compliance. Construction-in-progress balances are transferred to electric generation and distribution assets when an asset group is ready for its intended use. Government subsidies, liquidated damages recovered for construction delays, and income tax credits are recorded as a reduction to property, plant and equipment and reflected in cash flows from investing activities. Maintenance and repairs are charged to expense as incurred.

Depreciation, after consideration of salvage value and asset retirement obligations, is computed using the straight-line method over the estimated useful lives of the assets, which are determined on a composite or component basis. Capital spare parts, including rotable spare parts, are included in electric generation and distribution assets. If the spare part is considered a component, it is depreciated over its useful life after the part is placed in service. If the spare part is deemed part of a composite asset, the part is depreciated over the composite useful life even when being held as a spare part.

Certain of the Company's subsidiaries operate under concession contracts. Certain estimates are utilized to determine depreciation expense for the subsidiaries, including the useful lives of the property, plant and equipment and the amounts to be recovered at the end of the concession contract. The amounts to be recovered under these concession contracts are based on estimates that are inherently uncertain and actual amounts recovered may differ from those estimates. These concession contracts are not within the scope of ASC 853—*Service Concession Arrangements*.

Intangible Assets Subject to Amortization — Finite-lived intangible assets are amortized over their useful lives which range from 1 – 50 years and are included in the Consolidated Balance Sheet line item *Other intangible assets.* The Company accounts for purchased emission allowances as intangible assets and records an expense when they are utilized or sold. Granted emission allowances are valued at zero.

Impairment of Long-lived Assets — When circumstances indicate the carrying amount of long-lived assets in a held-for-use asset group may not be recoverable, the Company evaluates the assets for potential impairment using internal projections of undiscounted cash flows resulting from the use and eventual disposal of the assets. Events or changes in circumstances that may necessitate a recoverability evaluation include, but are not limited to, adverse changes in the regulatory environment, unfavorable changes in power prices or fuel costs, increased competition due to additional capacity in the grid, technological advancements, declining trends in demand, or an expectation it is more likely than not that the asset will be disposed of before the end of its previously estimated useful life. If the carrying amount of the assets exceeds the undiscounted cash flows, an impairment expense is recognized for the amount by which the carrying amount of the asset group exceeds its fair value (subject to the carrying amount not being reduced below fair value for any individual long-lived asset that is determinable without undue cost and effort). An impairment expense for certain assets may be reduced by the establishment of a regulatory asset if recovery through approved rates is probable.

SERVICE CONCESSION ASSETS — Service concession assets are stated at cost, net of accumulated amortization, in accordance with ASC 853. Service concession assets represent the cost of all infrastructure to be transferred to the public-sector entity grantors at the end of the concession. These costs primarily represent construction progress payments, engineering costs, insurance costs, salaries, interest and other costs directly relating to construction of the service concession infrastructure. Government subsidies, liquidated damages recovered for construction delays and income tax credits are recorded as a reduction to Service Concession Assets. Service concession assets are amortized and recognized in earnings as a cost of goods sold as infrastructure construction revenue is recognized. Services provided under concession arrangements are recognized on a straight line basis. Effective January 1, 2018, the Company derecognized the service concession assets and recognized a loan receivable under ASC 606. See further detail in the new accounting pronouncements discussion below.

DEBT ISSUANCE COSTS — Costs incurred in connection with the issuance of long-term debt are deferred and presented as a direct reduction from the face amount of that debt and amortized over the related financing period using the effective interest method. Debt issuance costs related to a line-of-credit or revolving credit facility are deferred and presented as an asset and amortized over the related financing period. Make-whole payments in connection with early debt retirements are classified as cash flows used in financing activities.

GOODWILL AND INDEFINITE-LIVED INTANGIBLE ASSETS — The Company evaluates goodwill and indefinite-lived intangible assets for impairment on an annual basis and whenever events or changes in circumstances necessitate an evaluation for impairment. The Company's annual impairment testing date is October 1.

Goodwill — Goodwill represents the excess of the purchase price of the business acquisition over the fair value of identifiable net assets acquired. Goodwill resulting from an acquisition is assigned to the reporting units that are expected to benefit from the synergies of the acquisition. Generally, each AES business with a goodwill balance constitutes a reporting unit as they are not similar to other businesses in a segment nor are they reported to segment management together with other businesses.

Goodwill is evaluated for impairment either under the qualitative assessment option or the quantitative test option to determine the fair value of the reporting unit. If goodwill is determined to be impaired, an impairment loss measured at the amount by which the reporting unit’s carrying amount exceeds its fair value, not to exceed the carrying amount of goodwill, is recorded.

Indefinite-Lived Intangible Assets — The Company's indefinite-lived intangible assets primarily include land-use rights and water rights. Indefinite-lived intangible assets are evaluated for impairment either under the qualitative assessment option or the two-step quantitative test. If the carrying amount of an intangible asset being tested for impairment exceeds its fair value, the excess is recognized as impairment expense.

ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES — Accounts payable consists of amounts due to trade creditors related to the Company's core business operations. These payables include amounts owed to vendors and suppliers for items such as energy purchased for resale, fuel, maintenance, inventory and other raw materials. Other accrued liabilities include items such as income taxes, regulatory liabilities, legal contingencies and employee-related costs, including payroll, and benefits.

REGULATORY ASSETS AND LIABILITIES — The Company recognizes assets and liabilities that result from regulated ratemaking processes. Regulatory assets generally represent incurred costs which have been deferred due to the probable future recovery via customer rates. Generally, returns earned on regulatory assets are reflected in the Consolidated Statement of Operations within *Interest Income*. Regulatory liabilities generally represent obligations to refund customers. Management continually assesses whether regulatory assets are probable of future recovery and regulatory liabilities are probable of future payment by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities, and the status of any pending or potential deregulation legislation. If future recovery of costs previously deferred ceases to be probable, the related regulatory assets are written off and recognized in income from continuing operations.

PENSION AND OTHER POSTRETIREMENT PLANS — The Company recognizes in its Consolidated Balance Sheets an asset or liability reflecting the funded status of pension and other postretirement plans with current-year changes in actuarial gains or losses recognized in AOCL, except for those plans at certain of the Company's regulated utilities that can recover portions of their pension and postretirement obligations through future rates. All plan assets are recorded at fair value. AES follows the measurement date provisions of the accounting guidance, which require a year-end measurement date of plan assets and obligations for all defined benefit plans.

INCOME TAXES — Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of the existing assets and liabilities, and their respective income tax basis. The Company establishes a valuation allowance when it is more likely than not that all or a portion of a deferred tax asset will not be realized. The Company's tax positions are evaluated under a more likely than not recognition threshold and measurement analysis before they are recognized for financial statement reporting.

Uncertain tax positions have been classified as noncurrent income tax liabilities unless expected to be paid within one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations.

The Company has elected to treat GILTI as an expense in the period in which the tax is accrued. Accordingly, no deferred tax assets or liabilities are recorded related to GILTI.

ASSET RETIREMENT OBLIGATIONS — The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the obligation is incurred. When a new liability is recognized, the Company capitalizes the costs of the liability by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the obligation, the Company eliminates the liability and, based on the actual cost to retire, may incur a gain or loss.

FOREIGN CURRENCY TRANSLATION — A business's functional currency is the currency of the primary economic environment in which the business operates and is generally the currency in which the business generates and expends cash. Subsidiaries and affiliates whose functional currency is a currency other than the U.S. dollar translate their assets and liabilities into U.S. dollars at the current exchange rates in effect at the end of the fiscal period. Adjustments arising from the translation of the balance sheet of such subsidiaries are included in AOCL. The revenue and expense accounts of such subsidiaries and affiliates are translated into U.S. dollars at the average exchange rates for the period. Gains and losses on intercompany foreign currency transactions that are long-term in nature and which the Company does not intend to settle in the foreseeable future, are also recognized in AOCL. Gains and losses that arise from exchange rate fluctuations on transactions denominated in a currency other than the functional currency are included in determining net income. Accumulated foreign currency translation adjustments are reclassified from AOCL to net income only when realized upon sale or upon complete or substantially complete liquidation of the investment in a foreign entity. The accumulated adjustments are included in carrying amounts in impairment assessments where the Company has committed to a plan that will cause the accumulated adjustments to be reclassified to earnings.

REVENUE RECOGNITION — Revenue is earned from the sale of electricity from our utilities and the production and sale of electricity and capacity from our generation facilities. Revenue is recognized upon the transfer of control of promised goods or services to customers in an amount that reflects the consideration to which we expect to be entitled in exchange for those goods or services. Revenue is recorded net of any taxes assessed on and collected from customers, which are remitted to the governmental authorities.

Utilities — Our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. The majority of our utility contracts have a single performance obligation, as the promises to transfer energy, capacity, and other distribution and/or transmission services are not distinct. Additionally, as the performance obligation is satisfied over time as energy is delivered, and the same method is used to measure progress, the performance obligation meets the criteria to be considered a series. Utility revenue is classified as regulated on the Consolidated Statements of Operations.

In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices ("tariffs") that our utilities are allowed to charge customers for electricity. Since tariffs are determined by the regulator, the price that our utilities have the right to bill corresponds directly with the value to the customer of the utility's performance completed in each period. The Company also has some month-to-month contracts. Revenue under these contracts is recognized using an output method measured by the MWh delivered each month, which best depicts the transfer of goods or services to the customer, at the approved tariff.

The Company has businesses where it sells and purchases power to and from ISOs and RTOs. Our utility businesses generally purchase power to satisfy the demand of customers that is not contracted through separate PPAs. In these instances, the Company accounts for these transactions on a net hourly basis because the transactions are settled on a net hourly basis. In limited situations, a utility customer may choose to receive generation services from a third-party provider, in which case the Company may serve as a billing agent for the provider and recognize revenue on a net basis.

Generation — Most of our generation fleet sells electricity under contracts to customers such as utilities, industrial users, and other intermediaries. Our generation contracts, based on specific facts and circumstances, can have one or more performance obligations as the promise to transfer energy, capacity, and other services may or may not be distinct depending on the nature of the market and terms of the contract. As the performance obligations are generally satisfied over time and use the same method to measure progress, the performance obligations meet the criteria to be considered a series. In measuring progress toward satisfaction of a performance obligation, the Company applies the "right to invoice" practical expedient when available, and recognizes revenue in the amount to which the Company has a right to consideration from a customer that corresponds directly with the value of the performance completed to date. Revenue from generation businesses is classified as non-regulated on the Consolidated Statements of Operations.

For contracts determined to have multiple performance obligations, we allocate revenue to each performance obligation based on its relative standalone selling price using a market or expected cost plus margin approach. Additionally, the Company allocates variable consideration to one or more, but not all, distinct goods or services that form part of a single performance obligation when (1) the variable consideration relates specifically to the efforts to transfer the distinct good or service and (2) the variable consideration depicts the amount to which the Company expects to be entitled in exchange for transferring the promised good or service to the customer.

Revenue from generation contracts is recognized using an output method, as energy and capacity delivered best depicts the transfer of goods or services to the customer. Performance obligations including energy or ancillary services (such as operations and maintenance and dispatch services) are generally measured by the MWh delivered. Capacity, which is a stand-ready obligation to deliver energy when required by the customer, is measured using MWs. In certain contracts, if plant availability exceeds a contractual target, the Company may receive a performance bonus payment, or if the plant availability falls below a guaranteed minimum target, we may incur a non-availability penalty. Such bonuses or penalties represent a form of variable consideration and are estimated and recognized when it is probable that there will not be a significant reversal.

In assessing whether variable quantities are considered variable consideration or an option to acquire additional goods and services, the Company evaluates the nature of the promise and the legally enforceable rights in the contract. In some contracts, such as requirement contracts, the legally enforceable rights merely give the customer a right to purchase additional goods and services which are distinct. In these contracts, the customer's action results in a new obligation, and the variable quantities are considered an option.

When energy or capacity is sold or purchased in the spot market or to ISOs, the Company assesses the facts and circumstances to determine gross versus net presentation of spot revenues and purchases. Generally, the nature of the performance obligation is to sell surplus energy or capacity above contractual commitments, or to purchase energy or capacity to satisfy deficits. Generally, on an hourly basis, a generator is either a net seller or a net buyer in terms of the amount of energy or capacity transacted with the ISO. In these situations, the Company recognizes revenue for the hours where the generator is a net seller and cost of sales for the hours where the generator is a net buyer.

Certain generation contracts contain operating leases where capacity payments are generally considered lease elements. In such cases, the allocation between the lease and non-lease elements is made at the inception of the lease following the guidance in ASC 840. Minimum lease payments from such contracts are recognized as revenue on a straight-line basis over the lease term whereas contingent rentals are recognized when earned.

The transaction price allocated to a construction performance obligation is recognized as revenue over time as construction activity occurs, with revenue being fully recognized upon completion of construction. These contracts may include a difference in timing between revenue recognition and the collection of cash receipts, which may be collected over the term of the entire arrangement. The timing difference could result in a significant financing component for the construction performance obligation if determined to be a material component of the transaction price. The Company accounts for a significant financing component under the effective interest rate method, recognizing a long-term receivable for the expected future payments related to the construction performance obligation in the *Loan Receivable* line item on the Consolidated Balance Sheets. As payments are collected from the customer over the term of the contract, consideration related to the construction performance obligation is bifurcated between the principal repayment of the long-term receivable and the related interest income, recognized in the Consolidated Statements of Operations.

SHARE-BASED COMPENSATION — The Company grants share-based compensation in the form of stock options, restricted stock units, performance stock units, and performance cash units. The expense is based on the grant-date fair value of the equity or liability instrument issued and is recognized on a straight-line basis over the requisite service period, net of estimated forfeitures. The Company uses a Black-Scholes option pricing model to estimate the fair value of stock options granted to its employees.

GENERAL AND ADMINISTRATIVE EXPENSES — General and administrative expenses include corporate and other expenses related to corporate staff functions and initiatives, primarily executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments. Additionally, all costs associated with corporate business development efforts are classified as general and administrative expenses.

DERIVATIVES AND HEDGING ACTIVITIES — Under the accounting standards for derivatives and hedging, the Company recognizes all contracts that meet the definition of a derivative, except those designated as normal purchase or normal sale at inception, as either assets or liabilities in the Consolidated Balance Sheets and measures those instruments at fair value. See Note 4—*Fair Value* and *Fair value* in this section for additional discussion regarding the determination of fair value.

PPAs and fuel supply agreements are evaluated to assess if they contain either a derivative or an embedded derivative requiring separate valuation and accounting. Generally, these agreements do not meet the definition of a derivative, often due to the inability to be net settled. On a quarterly basis, we evaluate the markets for commodities to be delivered under these agreements to determine if facts and circumstances have changed such that the agreements could be net settled and meet the definition of a derivative.

The Company typically designates its derivative instruments as cash flow hedges if they meet the criteria specified in ASC 815, *Derivatives and Hedging*. The Company enters into interest rate swap agreements in order to hedge the variability of expected future cash interest payments. Foreign currency contracts are used to reduce risks arising from the change in fair value of certain foreign currency denominated assets and liabilities. The objective of these practices is to minimize the impact of foreign currency fluctuations on operating results. The Company also enters into commodity contracts to economically hedge price variability inherent in electricity sales arrangements. The objectives of the commodity contracts are to minimize the impact of variability in spot electricity prices and stabilize estimated revenue streams. The Company does not use derivative instruments for speculative purposes.

For our hedges, changes in fair value that are considered highly effective are deferred in AOCL and are recognized into earnings as the hedged transactions affect earnings. Any ineffectiveness is recognized in earnings immediately. If a derivative is no longer highly effective, hedge accounting will be discontinued prospectively. For cash flow hedges of forecasted transactions, AES estimates the future cash flows of the forecasted transactions and evaluates the probability of the occurrence and timing of such transactions.

Changes in the fair value of derivatives not designated and qualifying as cash flow hedges are immediately recognized in earnings. Regardless of when gains or losses on derivatives are recognized in earnings, they are generally classified as interest expense for interest rate and cross-currency derivatives, foreign currency transaction gains or losses for foreign currency derivatives, and non-regulated revenue or non-regulated cost of sales for commodity and other derivatives. Cash flows arising from derivatives are included in the Consolidated Statements of Cash Flows as an operating activity given the nature of the underlying risk being economically hedged and the lack of significant financing elements, except that cash flows on designated and qualifying hedges of variable-rate interest during construction are classified as an investing activity. The Company has elected not to offset net derivative positions in the financial statements.

NEW ACCOUNTING PRONOUNCEMENTS — The following table provides a brief description of recent accounting pronouncements that had an impact on the Company's consolidated financial statements. Accounting pronouncements not listed below were assessed and determined to be either not applicable or did not have a material impact on the Company's consolidated financial statements.

New Accounting Standards Adopted			
ASU Number and Name	**Description**	**Date of Adoption**	**Effect on the financial statements upon adoption**
2018-15, Intangibles— Goodwill and Other— Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract	This standard aligns the accounting for implementation costs incurred for a cloud computing arrangement that is a service with the requirement for capitalizing implementation costs associated with developing or obtaining internal-use software. Transition method: retrospective or prospective.	October 1, 2018	The Company elected to early-adopt this standard on a prospective basis, effective for fiscal year 2018. The adoption of this standard did not have a material impact on the financial statements.
2018-14, Compensation — Retirement Benefits — Defined Benefit Plans — General (Subtopic 715-20): Disclosure Framework	This standard modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. Transition method: retrospective.	Early adoption elected, January 1, 2018	Impact limited to changes in financial statement disclosures.
2017-07, Compensation — Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost	This standard changes the presentation of non-service costs associated with defined benefit and other postretirement plans and updates the guidance so that only the service cost component will be eligible for capitalization. Transition method: retrospective for presentation of non-service cost and prospective for the change in capitalization.	January 1, 2018	For the year ended December 31, 2017 and 2016, $1 million and $3 million of non-service costs associated with defined benefit and other postretirement plans were reclassified from Costs of Sales to Other Expense, respectively.
2017-05, Other Income — Gains and Losses from the Derecognition of Nonfinancial Assets (Topic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets	This standard clarifies the scope and application of ASC 610-20 on the sale, transfer, and derecognition of nonfinancial assets and in substance nonfinancial assets to non-customers, including partial sales. It also provides guidance on how gains and losses on transfers of nonfinancial assets and in substance nonfinancial assets to non-customers are recognized. The standard also clarifies that the derecognition of businesses is under the scope of ASC 810. The standard must be adopted concurrently with ASC 606, however an entity will not have to apply the same transition method as ASC 606. Transition method: modified retrospective.	January 1, 2018	Following adoption of ASU 2017-01, fewer transactions are expected to meet the definition of a business under the scope of ASC 810 and will fall under the scope under this standard.

2017-04, Intangibles — Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment	This standard simplifies the accounting for goodwill impairments by removing the requirement to calculate the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if it had been acquired in a business combination. Instead, it requires that an entity record an impairment charge based on the amount by which a reporting unit's carrying amount exceeds its fair value, not to exceed the total amount of goodwill allocated to that reporting unit. Transition method: prospective.	October 1, 2018	In anticipation of our annual goodwill process, the Company early-adopted this standard to ease the administrative burden for the measurement of any potential goodwill impairment losses. There was no impact to the financial statements upon adoption of the standard.
2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business	The standard requires an entity to first evaluate whether substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, and if that threshold is met, the set is not a business. As a second step, at least one substantive process should exist to be considered a business. Transition method: prospective.	January 1, 2018	Some acquisitions and dispositions are expected to now fall under a different accounting model. This will reduce the number of transactions that are accounted for as business combinations and therefore future acquired goodwill.
2016-18, Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)	This standard requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. Transition method: retrospective.	January 1, 2018	For the years ended December 31, 2017 and 2016, cash provided by operating activities increased by $15 million and $13 million, respectively, cash used in investing activities decreased by $150 million and increased by $28 million, respectively, and cash provided by financing activities was unchanged.
2016-01, Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities	The standard significantly revises an entity’s accounting related to (1) classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosures of financial instruments. Transition method: modified retrospective. Prospective for equity investments without readily determinable fair value.	January 1, 2018	No material impact upon adoption of the standard.
2014-09, 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-10, 2017-13, Revenue from Contracts with Customers (Topic 606)	See discussion of the ASU below.	January 1, 2018	See impact upon adoption of the standard below.

On January 1, 2018, the Company adopted ASU 2014-09, "Revenue from Contracts with Customers," and its subsequent corresponding updates ("ASC 606"). Under this standard, an entity shall recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Company applied the modified retrospective method of adoption to the contracts that were not completed as of January 1, 2018. Results for reporting periods beginning January 1, 2018 are presented under ASC 606, while prior period amounts were not adjusted and continue to be reported in accordance with the previous revenue recognition standard. For contracts that were modified before January 1, 2018, the Company reflected the aggregate effect of all modifications when identifying the satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price.

The cumulative effect to our January 1, 2018 Consolidated Balance Sheet resulting from the adoption of ASC 606 was as follows (in millions):

Consolidated Balance Sheet	Balance at December 31, 2017	Adjustments Due to ASC 606	Balance at January 1, 2018
Assets			
Other current assets	$ 630	$ 61	$ 691
Deferred income taxes	130	(24)	106
Service concession assets, net	1,360	(1,360)	—
Loan receivable	—	1,490	1,490
Equity			
Accumulated deficit	(2,276)	67	(2,209)
Accumulated other comprehensive loss	(1,876)	19	(1,857)
Noncontrolling interest	2,380	81	2,461

The Mong Duong II power plant in Vietnam is the primary driver of changes in revenue recognition under the new standard. This plant is operated under a build, operate, and transfer contract and will be transferred to the Vietnamese government after the completion of a 25-year PPA. Under the previous revenue recognition standard, construction costs were deferred to a service concession asset, which was expensed in proportion to revenue recognized for the construction element over the term of the PPA. Under ASC 606, construction revenue and associated costs are recognized as construction activity occurs. As construction of the plant was substantially completed in 2015, revenues and costs associated with the construction were recognized through retained earnings, and the service concession asset was derecognized. A loan receivable was recognized for the future expected payments for the construction performance obligation. As the payments for the construction performance obligation occur over a 25-year term, a significant financing element was determined to exist which is accounted for under the effective interest rate method. The other performance obligation to operate and maintain the facility is measured based on the capacity made available.

The impact to our Consolidated Balance Sheet as of December 31, 2018 resulting from the adoption of ASC 606 as compared to the previous revenue recognition standard was as follows (in millions):

	December 31, 2018		
Consolidated Balance Sheet	As Reported	Balances Without Adoption of ASC 606	Adoption Impact
Assets			
Other current assets	$ 807	$ 741	$ 66
Deferred income taxes	97	122	(25)
Service concession assets, net	—	1,261	(1,261)
Loan receivable	1,423	—	1,423
TOTAL ASSETS	32,521	32,318	203
Equity			
Accumulated deficit	(1,005)	(1,112)	107
Accumulated other comprehensive loss	(2,071)	(2,088)	17
Noncontrolling interest	2,396	2,317	79
TOTAL LIABILITIES AND EQUITY	32,521	32,318	203

The impact to our Consolidated Statement of Operations for the year ended December 31, 2018 resulting from the adoption of ASC 606 as compared to the previous revenue recognition standard was as follows (in millions):

	Year Ended December 31, 2018		
Consolidated Statement of Operations	As Reported	Balances Without Adoption of ASC 606	Adoption Impact
Total revenue	$ 10,736	$ 10,800	$ (64)
Total cost of sales	(8,163)	(8,207)	44
Operating margin	2,573	2,593	(20)
Interest income	310	252	58
Other Income	72	70	2
Income from continuing operations before taxes and equity in earnings of affiliates	2,018	1,978	40
INCOME FROM CONTINUING OPERATIONS	1,349	1,309	40
NET INCOME	1,565	1,525	40
NET INCOME ATTRIBUTABLE TO THE AES CORPORATION	1,203	1,163	40

New Accounting Pronouncements Issued But Not Yet Effective — The following table provides a brief description of recent accounting pronouncements that could have a material impact on the Company's consolidated financial statements once adopted. Accounting pronouncements not listed below were assessed and determined to be either not applicable or are expected to have no material impact on the Company's consolidated financial statements.

New Accounting Standards Issued But Not Yet Effective			
ASU Number and Name	**Description**	**Date of Adoption**	**Effect on the financial statements upon adoption**
2018-02, Income Statement — Reporting Comprehensive Income (Topic 220), Reclassification of Certain Tax Effects from AOCI	This amendment allows a reclassification of the stranded tax effects resulting from the implementation of the Tax Cuts and Jobs Act from AOCI to retained earnings. Because this amendment only relates to the reclassification of the income tax effects of the Tax Cuts and Jobs Act, the underlying guidance that requires that the effect of a change in tax laws or rates be included in income from continuing operations is not affected.	January 1, 2019. Early adoption is permitted.	The Company does not expect any impact on its consolidated financial statements upon adoption of the standard on January 1, 2019.
2017-12, Derivatives and Hedging (Topic 815): Targeted improvements to Accounting for Hedging Activities	The standard updates the hedge accounting model to expand the ability to hedge nonfinancial and financial risk components, reduce complexity, and ease certain documentation and assessment requirements. When facts and circumstances are the same as at the previous quantitative test, a subsequent quantitative effectiveness test is not required. The standard also eliminates the requirement to separately measure and report hedge ineffectiveness. For cash flow hedges, this means that the entire change in the fair value of a hedging instrument will be recorded in other comprehensive income and amounts deferred will be reclassified to earnings in the same income statement line as the hedged item in the period in which it settles. Transition method: modified retrospective with the cumulative effect adjustment recorded to the opening balance of retained earnings as of the initial application date. Prospective for presentation and disclosures.	January 1, 2019. Early adoption is permitted.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2016-13, Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments	The standard updates the impairment model for financial assets measured at amortized cost. For trade and other receivables, held-to-maturity debt securities, loans and other instruments, entities will be required to use a new forward-looking "expected loss" model that generally will result in the earlier recognition of allowance for losses. For available-for-sale debt securities with unrealized losses, entities will measure credit losses as it is done today, except that the losses will be recognized as an allowance rather than a reduction in the amortized cost of the securities. Transition method: various.	January 1, 2020. Early adoption is permitted only as of January 1, 2019.	The Company is currently evaluating the impact of adopting the standard on its consolidated financial statements.
2016-02, 2018-01, 2018-10, 2018-11, 2018-20 Leases (Topic 842)	See discussion of the ASU below.	January 1, 2019. Early adoption is permitted.	The Company will adopt the standard on January 1, 2019; see below for the evaluation of the impact of its adoption on the consolidated financial statements.

ASU 2016-02 and its subsequent corresponding updates require lessees to recognize assets and liabilities for most leases, and recognize expenses in a manner similar to the current accounting method. For lessors, the guidance modifies the lease classification criteria and the accounting for sales-type and direct financing leases. The guidance also eliminates current real estate-specific provisions.

The standard must be adopted using a modified retrospective approach. The FASB has provided an optional transition method, which the Company has elected, that allows entities to continue to apply the guidance in ASC 840 Leases to the comparative periods presented in the year of adoption. Under this transition method, the Company will apply the transition provisions starting on January 1, 2019.

The Company has elected to apply a package of practical expedients that allow lessees and lessors not to reassess: (1) whether any expired or existing contracts are or contain leases, (2) lease classification for any expired or existing leases, and (3) whether initial direct costs for any expired or existing leases qualify for capitalization under ASC 842. These three practical expedients must be elected as a package and must be consistently applied to all leases. The Company has also elected to apply an optional transition practical expedient for land easements that allows an entity to continue applying its current accounting policy for all land easements that exist before the standard's effective date that were not previously accounted for under ASC 840.

The Company established a task force focused on the identification of contracts that are under the scope of the new standard and the assessment and measurement of their corresponding right-of-use assets and related liabilities. Additionally, the implementation team has been working on the configuration of a lease accounting tool that will support the implementation and the subsequent accounting. The implementation team has also evaluated changes to our business processes, systems and controls to support recognition and disclosure under the new standard.

Under ASC 842, it is expected that fewer contracts will contain a lease. However, due to the elimination of the real estate-specific guidance and changes to certain lessor classification criteria, more leases will qualify as sales-type leases and direct financing leases. Under these two models, a lessor will derecognize the asset and will recognize a lease receivable. According to ASC 842, the lease receivable includes the fair value of the plant after the contract period but does not include any variable payments such as margin on the sale of energy. Therefore, the lease receivable could be significantly different than the carrying amount of the underlying asset at lease commencement. In such circumstances, the difference between the initially recognized lease receivable and the carrying amount of the underlying asset is recognized as a gain/loss at lease commencement.

The primary expected impact as of the effective date is the recognition of approximately $300 million of lease liabilities and the corresponding right of use assets for all contracts that contain an operating lease and for which the Company is the lessee. In addition, the Company expects to reclassify various account balances to different line items on the Consolidated Balance Sheet to reflect the new presentation requirements. Consolidated Statement of Operations presentation and the expense recognition pattern are not expected to change for lessees.

2. INVENTORY

Inventory is valued primarily using the average-cost method. The following table summarizes the Company's inventory balances as of the dates indicated (in millions):

December 31,	2018	2017
Fuel and other raw materials	$ 300	$ 284
Spare parts and supplies	277	278
Total	$ 577	$ 562

3. PROPERTY, PLANT AND EQUIPMENT

The following table summarizes the components of the electric generation and distribution assets and other property, plant and equipment (in millions) with their estimated useful lives (in years). The amounts are stated net of all prior asset impairment losses recognized.

		December 31,	
	Estimated Useful Life	2018	2017
Electric generation and distribution facilities	7-40	$ 22,875	$ 21,529
Other buildings	5-72	1,651	1,971
Furniture, fixtures and equipment	3-25	310	284
Other	5-44	406	335
Total electric generation and distribution assets and other		25,242	24,119
Accumulated depreciation		(8,227)	(7,942)
Net electric generation and distribution assets and other		$ 17,015	$ 16,177

The following table summarizes depreciation expense (including the amortization of assets recorded under capital leases and the amortization of asset retirement obligations) and interest capitalized during development and construction on qualifying assets for the periods indicated (in millions):

Years Ended December 31,	2018	2017	2016
Depreciation expense	$ 960	$ 1,005	$ 1,002
Interest capitalized during development and construction	199	139	118

Property, plant and equipment, net of accumulated depreciation, of $11 billion and $10 billion was mortgaged, pledged or subject to liens as of December 31, 2018 and 2017, respectively, including assets classified as held-for-sale.

The following table summarizes regulated and non-regulated generation and distribution property, plant and equipment and accumulated depreciation as of the dates indicated (in millions):

December 31,	2018	2017
Regulated generation, distribution assets and other, gross	$ 8,959	$ 8,093
Regulated accumulated depreciation	(3,504)	(3,357)
Regulated generation, distribution assets and other, net	5,455	4,736
Non-regulated generation, distribution assets and other, gross	16,283	16,026
Non-regulated accumulated depreciation	(4,723)	(4,585)
Non-regulated generation, distribution assets and other, net	11,560	11,441
Net electric generation, distribution assets and other	$ 17,015	$ 16,177

The following table presents amounts recognized related to asset retirement obligations for the periods indicated (in millions):

	2018	2017
Balance at January 1	$ 368	$ 357
Additional liabilities incurred	19	1
Liabilities settled	(14)	(21)
Accretion expense	18	16
Change in estimated cash flows	24	25
Other	—	(10)
Balance at December 31	$ 415	$ 368

The Company's asset retirement obligations include active ash landfills, water treatment basins and the removal or dismantlement of certain plants and equipment. The $24 million increase in estimated cash flows in 2018 is primarily due to an increase of $55 million in estimated ash pond closure costs and revised closure dates associated with an EPA rule regulating CCR at IPL and an increase in coal pile remediation costs at DPL. These were partially offset by a decrease of $32 million due to reductions in estimated closure costs associated with ash ponds and landfills at DPL resulting in a reduction to *Cost of Sales* on the Consolidated Statements of Operations.

The Company used the cost approach to determine the fair value of the ARO liabilities, which was estimated by discounting expected cash outflows to their present value using market based rates at the initial recording of the liabilities. Cash outflows were based on the approximate future disposal costs as determined by market information, historical information or other management estimates. These inputs to the fair value of the ARO liabilities are considered Level 3 inputs under the fair value hierarchy.

4. FAIR VALUE

The fair value of current financial assets and liabilities, debt service reserves and other deposits approximate their reported carrying amounts. The estimated fair values of the Company's assets and liabilities have been determined using available market information. Because these amounts are estimates and based on hypothetical transactions to sell assets or transfer liabilities, the use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Valuation Techniques — The fair value measurement accounting guidance describes three main approaches to measuring the fair value of assets and liabilities: (1) market approach, (2) income approach and (3) cost approach. The market approach uses prices and other relevant information generated from market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to convert future amounts to a single present value amount. The measurement is based on current market expectations of the return on those future amounts. The cost approach is based on the amount that would currently be required to replace an asset. The Company measures its investments and derivatives at fair value on a recurring basis. Additionally, in connection with annual or event-driven impairment evaluations, certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis. These include long-lived tangible assets (i.e., property, plant and equipment), goodwill and intangible assets (e.g., sales concessions, land use rights and water rights, etc.). In general, the Company determines the fair value of investments and derivatives using the market approach and the income approach, respectively. In the nonrecurring measurements of nonfinancial assets and liabilities, all three approaches are considered; however, the value estimated under the income approach is often the most representative of fair value.

Investments — The Company's investments measured at fair value generally consist of marketable debt and equity securities. Equity securities are either measured at fair value using quoted market prices or based on comparisons to market data obtained for similar assets. Debt securities primarily consist of unsecured debentures and certificates of deposit held by our Brazilian subsidiaries. Returns and pricing on these instruments are generally indexed to the market interest rates in Brazil. Debt securities are measured at fair value based on comparisons to market data obtained for similar assets.

Derivatives — Derivatives are measured at fair value using quoted market prices or the income approach utilizing volatilities, spot and forward benchmark interest rates (such as LIBOR and EURIBOR), foreign exchange rates, credit data, and commodity prices, as applicable. When significant inputs are not observable, the Company uses relevant techniques to determine the inputs, such as regression analysis or prices for similarly traded instruments available in the market.

The Company's methodology to fair value its derivatives is to start with any observable inputs; however, in certain instances the published forward rates or prices may not extend through the remaining term of the contract and management must make assumptions to extrapolate the curve, which necessitates the use of unobservable inputs, such as proxy commodity prices or historical settlements to forecast forward prices. Specifically, where there is limited forward curve data with respect to foreign exchange contracts, beyond the traded points, the Company utilizes the interest rate differential approach to construct the remaining portion of the forward curve. Similarly, in certain instances, the spread that reflects the credit or nonperformance risk is unobservable requiring the use of proxy yield curves of similar credit quality.

To determine the fair value of a derivative, cash flows are discounted using the relevant spot benchmark interest rate. The Company then makes a credit valuation adjustment ("CVA"), as applicable, by further discounting the cash flows for nonperformance or credit risk based on the observable or estimated debt spread of the Company's subsidiary or its counterparty and the tenor of the respective derivative instrument. The CVA for potential future scenarios in which the derivative is in an asset position is based on the counterparty's credit ratings, credit default swap spreads, and debt spreads, as available. The CVA for potential future scenarios in which the derivative is in a liability position is based on the Parent Company's or the subsidiary's current debt spread. In the absence of readily obtainable credit information, the Parent Company's or the subsidiary's estimated credit rating (based on applying a standard industry model to historical financial information and then considering other relevant information) and spreads of comparably rated entities or the respective country's debt spreads are used as a proxy. All derivative instruments are analyzed individually and are subject to unique risk exposures.

The fair value hierarchy of an asset or a liability is based on the level of significance of the input assumptions. An input assumption is considered significant if it affects the fair value by at least 10%. Assets and liabilities are classified as Level 3 when the use of unobservable inputs is significant. When the use of unobservable inputs is insignificant, assets and liabilities are classified as Level 2. Transfers between Level 3 and Level 2 are determined as of the end of the reporting period and result from changes in significance of unobservable inputs used to calculate the CVA.

Debt — Recourse and non-recourse debt are carried at amortized cost. The fair value of recourse debt is estimated based on quoted market prices. The fair value of non-recourse debt is estimated based upon interest rates and other features of the loan. In general, the carrying amount of variable rate debt is a close approximation of its fair value. For fixed rate loans, the fair value is estimated using quoted market prices or discounted cash flow ("DCF") analyses. The fair value of recourse and non-recourse debt excludes accrued interest at the valuation date. The fair value was determined using available market information as of December 31, 2018. The Company is not aware of any factors that would significantly affect the fair value amounts subsequent to December 31, 2018.

Nonrecurring measurements — For nonrecurring measurements derived using the income approach, fair value is generally determined using valuation models based on the principles of DCF. The income approach is most often used in the impairment evaluation of long-lived tangible assets, equity method investments, goodwill, and intangible assets. Where the use of market observable data is limited or not available for certain input assumptions, the Company develops its own estimates using a variety of techniques such as regression analysis and extrapolations. Depending on the complexity of a valuation, an independent valuation firm may be engaged to assist management in the valuation process.

For nonrecurring measurements derived using the market approach, recent market transactions involving the sale of identical or similar assets are considered. The use of this approach is limited because it is often difficult to identify sale transactions of identical or similar assets. This approach is used in impairment evaluations of certain intangible assets. Otherwise, it is used to corroborate the fair value determined under the income approach.

For nonrecurring measurements derived using the cost approach, fair value is typically based upon a replacement cost approach. This approach involves a considerable amount of judgment, which is why its use is limited to the measurement of long-lived tangible assets. Like the market approach, this approach is also used to corroborate the fair value determined under the income approach.

Fair Value Considerations — In determining fair value, the Company considers the source of observable market data inputs, liquidity of the instrument, the credit risk of the counterparty and the risk of the Company's or its counterparty's nonperformance. The conditions and criteria used to assess these factors are:

Sources of market assumptions — The Company derives most of its market assumptions from market efficient data sources (e.g., Bloomberg and Reuters). To determine fair value, where market data is not readily available, management uses comparable market sources and empirical evidence to develop its own estimates of market assumptions.

Market liquidity — The Company evaluates market liquidity based on whether the financial or physical instrument, or the underlying asset, is traded in an active or inactive market. An active market exists if the prices are fully transparent to market participants, can be measured by market bid and ask quotes, the market has a relatively large proportion of trading volume as compared to the Company's current trading volume and the market has a significant number of market participants that will allow the market to rapidly absorb the quantity of assets traded without significantly affecting the market price. Another factor the Company considers when determining whether a market is active or inactive is the presence of government or regulatory controls over pricing that could make it difficult to establish a market-based price when entering into a transaction.

Nonperformance risk — Nonperformance risk refers to the risk that an obligation will not be fulfilled and affects the value at which a liability is transferred or an asset is sold. Nonperformance risk includes, but may not be limited to, the Company or its counterparty's credit and settlement risk. Nonperformance risk adjustments are dependent on credit spreads, letters of credit, collateral, other arrangements available and the nature of master netting arrangements. The Company is party to various interest rate swaps and options; foreign currency options and forwards; and derivatives and embedded derivatives, which subject the Company to nonperformance risk. The financial and physical instruments held at the subsidiary level are generally non-recourse to the Parent Company.

Nonperformance risk on the investments held by the Company is incorporated in the fair value derived from quoted market data to mark the investments to fair value.

Recurring Measurements — The following table presents, by level within the fair value hierarchy, as described in Note 1—*General and Summary of Significant Accounting Policies,* the Company's financial assets and liabilities that were measured at fair value on a recurring basis as of the dates indicated (in millions). For the Company's investments in marketable debt and equity securities, the security classes presented were determined based on the nature and risk of the security and are consistent with how the Company manages, monitors and measures its marketable securities:

	December 31, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
DEBT SECURITIES:								
Available-for-sale:								
Unsecured debentures	$ —	$ 5	$ —	$ 5	$ —	$ 207	$ —	$ 207
Certificates of deposit	—	243	—	243	—	153	—	153
Total debt securities	—	248	—	248	—	360	—	360
EQUITY SECURITIES:								
Mutual funds	19	49	—	68	20	52	—	72
Total equity securities	19	49	—	68	20	52	—	72
DERIVATIVES:								
Interest rate derivatives	—	28	1	29	—	15	—	15
Cross-currency derivatives	—	6	—	6	—	29	—	29
Foreign currency derivatives	—	18	199	217	—	29	240	269
Commodity derivatives	—	6	4	10	—	30	5	35
Total derivatives — assets	—	58	204	262	—	103	245	348
TOTAL ASSETS	$ 19	$ 355	$ 204	$ 578	$ 20	$ 515	$ 245	$ 780
Liabilities								
DERIVATIVES:								
Interest rate derivatives	$ —	$ 67	$ 141	$ 208	$ —	$ 111	$ 151	$ 262
Cross-currency derivatives	—	5	—	5	—	3	—	3
Foreign currency derivatives	—	41	—	41	—	30	—	30
Commodity derivatives	—	3	—	3	—	19	1	20
Total derivatives — liabilities	—	116	141	257	—	163	152	315
TOTAL LIABILITIES	$ —	$ 116	$ 141	$ 257	$ —	$ 163	$ 152	$ 315

As of December 31, 2018, all AFS debt securities had stated maturities within one year. For the years ended December 31, 2018, 2017, and 2016, no other-than-temporary impairment of marketable securities were recognized in earnings or Other Comprehensive Income (Loss). Gains and losses on the sale of investments are determined using the specific-identification method. The following table presents gross proceeds from sale of AFS securities for the periods indicated (in millions):

Year Ended December 31,	2018	2017	2016
Gross proceeds from sale of AFS securities [1]	$ 1,403	$ 1,398	$ 1,726

[1] Proceeds include $119 million of non-cash proceeds from non-convertible debentures at Guaimbê Solar Complex. See Note 24—Acquisitions for further information.

Any Level 1 derivative instruments are exchange-traded commodity futures for which the pricing is observable in active markets, and as such, these are not expected to transfer to other levels. There have been no transfers between Level 1 and Level 2.

The following tables present a reconciliation of net derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the years ended December 31, 2018 and 2017 presented net by type of derivative. Transfers between Level 3 and Level 2 are determined as of the end of the reporting period and principally result from changes in the significance of unobservable inputs used to calculate the credit valuation adjustment (in millions).

Year Ended December 31, 2018	Interest Rate	Foreign Currency	Commodity	Total
Balance at January 1	$ (151)	$ 240	$ 4	$ 93
Total realized and unrealized gains (losses):				
Included in earnings	22	(14)	(1)	7
Included in other comprehensive income — derivative activity	(8)	—	—	(8)
Included in regulatory (assets) liabilities	—	—	5	5
Settlements	14	(27)	(4)	(17)
Transfers of assets/(liabilities), net into Level 3	(8)	—	—	(8)
Transfers of (assets)/liabilities, net out of Level 3	(9)	—	—	(9)
Balance at December 31	$ (140)	$ 199	$ 4	$ 63
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities held at the end of the period	$ 29	$ (41)	$ (1)	$ (13)

Year Ended December 31, 2017	Interest Rate	Foreign Currency	Commodity	Total
Balance at January 1	$ (179)	$ 255	$ 5	$ 81
Total realized and unrealized gains (losses):				
Included in earnings	(1)	21	1	21
Included in other comprehensive income — derivative activity	(23)	—	—	(23)
Included in regulatory (assets) liabilities	—	—	10	10
Settlements	36	(36)	(12)	(12)
Transfers of assets/(liabilities), net into Level 3	(4)	—	—	(4)
Transfers of (assets)/liabilities, net out of Level 3	20	—	—	20
Balance at December 31	$ (151)	$ 240	$ 4	$ 93
Total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets and liabilities held at the end of the period	$ 7	$ (15)	$ 1	$ (7)

The following table summarizes the significant unobservable inputs used for the Level 3 derivative assets (liabilities) as of December 31, 2018 (in millions, except range amounts):

Type of Derivative	Fair Value	Unobservable Input	Amount or Range (Weighted Average)
Interest rate	$ (140)	Subsidiaries' credit spreads	1.8% - 5.3% (3.7%)
Foreign currency:			
Argentine peso	199	Argentine peso to U.S. dollar currency exchange rate after one year	52.7 - 142.6 (96.1)
Commodity:			
Other	4		
Total	$ 63		

For interest rate derivatives, and foreign currency derivatives, increases (decreases) in the estimates of the Company's own credit spreads would decrease (increase) the value of the derivatives in a liability position. For foreign currency derivatives, increases (decreases) in the estimate of the above exchange rate would increase (decrease) the value of the derivative.

Nonrecurring Measurements

When evaluating impairment of long-lived assets and equity method investments, the Company measures fair value using the applicable fair value measurement guidance. Impairment expense is measured by comparing the fair value at the evaluation date to their then-latest available carrying amount. The following table summarizes major categories of assets and liabilities measured at fair value on a nonrecurring basis during the period and their level within the fair value hierarchy (in millions):

Year Ended December 31, 2018	Measurement	Carrying	Fair Value			Pre-tax
Assets	Date	Amount (1)	Level 1	Level 2	Level 3	Loss
Dispositions and held-for-sale businesses:						
Shady Point	12/31/2018	$ 211	$ —	$ —	$ 30	$ 157
Long-lived assets held and used: (2)						
Nejapa	12/31/2018	42	—	—	5	37
Equity method investments:						
Guacolda	10/01/2018	354	—	—	209	144
Elsta	09/30/2018	19	—	16	—	3

Year Ended December 31, 2017	Measurement	Carrying	Fair Value			Pre-tax
Assets	Date	Amount (1)	Level 1	Level 2	Level 3	Loss
Long-lived assets held and used: (2)						
Laurel Mountain	12/31/2017	$ 154	$ —	$ —	$ 33	$ 121
Kilroot	12/31/2017	69	—	—	20	37
DPL	02/28/2017	77	—	—	11	66
Other	Various	18	—	—	—	18
Dispositions and held-for-sale businesses:						
DPL Peaker Assets	12/31/2017	346	—	237	—	109
Kazakhstan Hydroelectric (3)	06/30/2017	190	—	92	—	92
Kazakhstan CHPs	03/31/2017	171	—	29	—	94

(1) Represents the carrying values at the dates of initial measurement, before fair value adjustment.
(2) See Note 20—*Asset Impairment Expense* for further information.
(3) Per the Company's policy, pre-tax loss is limited to the impairment of long-lived assets. Any additional loss will be recognized on completion of the sale. Upon disposal of Kazakhstan HPPs, the Company incurred an additional pre-tax loss on disposal of $33 million. See Note 20—*Asset Impairment Expense* and Note 23—*Held-for-Sale and Dispositions* for further information.

The following table summarizes the significant unobservable inputs used in the Level 3 measurement of long-lived assets held and used measured on a nonrecurring basis during the year ended December 31, 2018 (in millions, except range amounts):

December 31, 2018	Fair Value	Valuation Technique	Unobservable Input	Range (Weighted Average)
Long-lived assets held and used:				
Nejapa	5	Discounted cash flow	Annual revenue growth	-70% to -1% (-15%)
			Pre-tax operating margin	37% to 82% (59%)
			Weighted-average cost of capital	12%
Equity method invesments:				
Guacolda	209	Discounted cash flow	Annual dividend growth	-70% to 467% (48%)
			Weighted-average cost of equity	10%
Total	$ 214			

When determining the fair value of the Shady Point held-for-sale asset group, the Company used the market approach based on prices and unobservable inputs from transactions involving comparable assets as the inputs for the Level 3 nonrecurring measurement.

Financial Instruments not Measured at Fair Value in the Consolidated Balance Sheets

The following table presents the carrying amount, fair value and fair value hierarchy of the Company's financial assets and liabilities that are not measured at fair value in the Consolidated Balance Sheets as of the periods indicated, but for which fair value is disclosed (in millions).

		December 31, 2018				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent [(1)]	$ 100	$ 209	$ —	$ —	$ 209
Liabilities:	Non-recourse debt	15,645	16,225	—	13,524	2,701
	Recourse debt	3,655	3,621	—	3,621	—

		December 31, 2017				
		Carrying Amount	Fair Value			
			Total	Level 1	Level 2	Level 3
Assets:	Accounts receivable — noncurrent [(1)]	$ 163	$ 217	$ —	$ 6	$ 211
Liabilities:	Non-recourse debt	15,340	15,890	—	13,350	2,540
	Recourse debt	4,630	4,920	—	4,920	—

(1) These amounts primarily relate to amounts due from CAMMESA, the administrator of the wholesale electricity market in Argentina, and are included in *Other noncurrent assets* in the accompanying Consolidated Balance Sheets. The fair value and carrying amount of these receivables exclude VAT of $16 million and $31 million as of December 31, 2018 and 2017, respectively.

5. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Volume of Activity — The following table presents the Company's maximum notional (in millions) over the remaining contractual period by type of derivative as of December 31, 2018, regardless of whether they are in qualifying cash flow hedging relationships, and the dates through which the maturities for each type of derivative range:

Derivatives	Maximum Notional Translated to USD	Latest Maturity
Interest Rate (LIBOR and EURIBOR)	$ 4,584	2044
Cross-currency Swaps (Chilean Unidad de Fomento and Chilean peso)	344	2029
Foreign Currency:		
Argentine peso	68	2026
Chilean peso	270	2021
Colombian peso	117	2021
Brazilian real	23	2019
Others, primarily with weighted average remaining maturities of a year or less	112	2021

Accounting and Reporting *— Assets and Liabilities —* The following tables present the fair value of assets and liabilities related to the Company's derivative instruments as of the periods indicated (in millions):

Fair Value	December 31, 2018			December 31, 2017		
Assets	Designated	Not Designated	Total	Designated	Not Designated	Total
Interest rate derivatives	$ 29	$ —	$ 29	$ 15	$ —	$ 15
Cross-currency derivatives	6	—	6	29	—	29
Foreign currency derivatives	—	217	217	8	261	269
Commodity derivatives	—	10	10	5	30	35
Total assets	$ 35	$ 227	$ 262	$ 57	$ 291	$ 348
Liabilities						
Interest rate derivatives	$ 205	$ 3	$ 208	$ 125	$ 137	$ 262
Cross-currency derivatives	5	—	5	3	—	3
Foreign currency derivatives	28	13	41	1	29	30
Commodity derivatives	—	3	3	9	11	20
Total liabilities	$ 238	$ 19	$ 257	$ 138	$ 177	$ 315

	December 31, 2018		December 31, 2017	
Fair Value	Assets	Liabilities	Assets	Liabilities
Current	$ 75	$ 51	$ 84	$ 211
Noncurrent	187	206	264	104
Total	$ 262	$ 257	$ 348	$ 315

As of December 31, 2018, all derivative instruments subject to credit risk-related contingent features were in an asset position.

Credit Risk-Related Contingent Features [(1)]	December 31, 2017
Present value of liabilities subject to collateralization	$ 15
Cash collateral held by third parties or in escrow	9

(1) Based on the credit rating of certain subsidiaries

Earnings and Other Comprehensive Income (Loss) — The following table presents the pre-tax gains (losses) recognized in AOCL and earnings related to all derivative instruments for the periods indicated (in millions):

	Years Ended December 31,		
	2018	2017	2016
Effective portion of cash flow hedges			
Gains (losses) recognized in AOCL			
Interest rate derivatives	$ (16)	$ (66)	$ (35)
Cross-currency derivatives	(26)	31	21
Foreign currency derivatives	(52)	(5)	(4)
Commodity derivatives	—	18	30
Total	$ (94)	$ (22)	$ 12
Gains (losses) reclassified from AOCL to earnings			
Interest rate derivatives	$ (52)	$ (82)	$ (101)
Cross-currency derivatives	(43)	34	8
Foreign currency derivatives	(16)	(20)	(8)
Commodity derivatives	(6)	17	56
Total	$ (117)	$ (51)	$ (45)
Loss reclassified from AOCL to earnings due to discontinuance of hedge accounting [(1)]	$ —	$ (13)	$ —
Gain (losses) recognized in earnings related to			
Ineffective portion of cash flow hedges	$ (7)	$ 3	$ (1)
Not designated as hedging instruments:			
Foreign currency derivatives	148	1	19
Commodity derivatives and other	25	14	(16)
Total	$ 173	$ 15	$ 3

(1) Cash flow hedge was discontinued because it was probable the forecasted transaction will not occur.

AOCL is expected to decrease pre-tax income from continuing operations for the twelve months ended December 31, 2019 by $59 million, primarily due to interest rate derivatives.

6. FINANCING RECEIVABLES

Receivables with contractual maturities of greater than one year are considered financing receivables, primarily related to amended agreements or government resolutions due from CAMMESA. The following table presents financing receivables by country as of the dates indicated (in millions):

December 31,	2018	2017
Argentina	$ 93	$ 177
Panama	14	—
Other	9	17
Total	$ 116	$ 194

Argentina

Collection of the principal and interest on these receivables is subject to various business risks and uncertainties, including, but not limited to, the continued operation of power plants which generate cash for payments of these receivables, regulatory changes that could impact the timing and amount of collections, and economic conditions in Argentina. The Company monitors these risks, including the credit ratings of the Argentine government, on a quarterly basis to assess the collectability of these receivables. The Company accrues interest on these receivables if collectability is reasonably assured. The Company's collection estimates are based on assumptions it believes to be reasonable, but are inherently uncertain. Actual future cash flows could differ from these estimates. The decrease in Argentina financing receivables was primarily due to planned collections and unfavorable FX impacts.

FONINVEMEM Agreements — As a result of energy market reforms in 2004 and 2010, AES Argentina entered into three agreements with the Argentine government, referred to as the FONINVEMEM Agreements, to contribute a portion of their accounts receivable into a fund for financing the construction of combined cycle and gas-fired plants. These receivables accrue interest and are collected in monthly installments over 10 years once the related plant begins operations. In addition, AES Argentina receives an ownership interest in these newly built plants once the receivables have been fully repaid.

The FONINVEMEM receivables are denominated in Argentine pesos, but indexed to U.S. dollars, which represents a foreign currency derivative. Due to differences between spot rates, used to remeasure the receivables, and discounted forward rates, used to value the foreign currency derivative, these two items will not perfectly offset over the life of the receivable. Once settled, the foreign currency derivative will offset the accumulated unrealized foreign currency losses resulting from the devaluation of the FONINVEMEM receivable. As of December 31, 2018 and 2017, the amount of the foreign currency-related derivative assets associated with the FONINVEMEM financing receivables that were excluded from the table above had a fair value of $199 million and $240 million, respectively.

The receivables under the FONINVEMEM Agreements have been actively collected since the related plants commenced operations in 2010 and 2016. In assessing the collectability of the receivables under these agreements, the Company also considers historic collection evidence in accordance with the agreements.

Other Agreements — Other agreements primarily consist of resolutions passed by the Argentine government in which AES Argentina will receive compensation for investments in new generation plants and technologies. The timing of collections depend on corresponding agreements and collectability of these receivables are assessed on an ongoing basis.

7. INVESTMENTS IN AND ADVANCES TO AFFILIATES

The following table summarizes the relevant effective equity ownership interest and carrying values for the Company's investments accounted for under the equity method as of the periods indicated:

December 31,		2018	2017	2018	2017
Affiliate	Country	Carrying Value (in millions)		Ownership Interest %	
sPower	United States	$ 515	$ 508	50%	50%
OPGC [1]	India	293	269	49%	49%
Guacolda [2]	Chile	209	357	33%	33%
Other affiliates [3]	Various	97	63		
Total		$ 1,114	$ 1,197		

(1) OPGC has one coal-fired project under development which is an expansion of our existing OPGC business. The project started construction in April 2014 and is expected to begin operations in 2019.
(2) The Company's ownership in Guacolda is held through AES Gener, a 67%-owned consolidated subsidiary. AES Gener owns 50% of Guacolda, resulting in an AES effective ownership in Guacolda of 33%.
(3) Includes Fluence, Simple Energy, Bosforo, Elsta, Distributed Energy equity method investments, and others.

Guacolda — In October 2018, an other-than-temporary impairment was identified at Guacolda primarily as a result of increased renewable generation in Chile lowering energy prices, impacting management's ability to re-contract Guacolda's generation after expiration of existing PPAs. A calculation of the fair value of Gener's investment in Guacolda was required to evaluate whether there was a loss in the carrying value of the investment. Based on management's estimate of fair value of $209 million, the Company recognized an other-than-temporary impairment of $144 million in *Other non-operating expense*. The Guacolda equity method investment is reported in the South America SBU reportable segment.

Distributed Energy — In December 2018, Distributed Energy acquired the remaining equity interest in a partnership holding various solar projects for consideration of $23 million. This transaction resulted in a loss of $5 million, reported in *Other expense* in the Consolidated Statement of Operations. The projects, previously recorded as equity method investments, have been consolidated. See Note 24—*Acquisitions* for further discussion.

Simple Energy — In April 2018, the Company invested $35 million in Simple Energy, a provider of utility-branded marketplaces and omni-channel instant rebates. As the Company does not control Simple Energy, the investment is accounted for as an equity method investment and is reported as part of Corporate and Other.

Fluence — On January 1, 2018, Siemens and AES closed on the creation of the Fluence joint venture with each party holding a 50% ownership interest. The Company contributed $7 million in cash and $20 million in non-cash assets from the AES Advancion energy storage development business as consideration for the transaction, and received an equity interest in Fluence with a fair value of $50 million. See Note 23—*Held-for-Sale and Dispositions* for further discussion. Fluence is a global energy storage technology and services company. As the Company does not control Fluence, the investment is accounted for as an equity method investment. The Fluence equity method investment is reported as part of Corporate and Other.

sPower — In February 2017, the Company and Alberta Investment Management Corporation (“AIMCo”) entered into an agreement to acquire FTP Power LLC (“sPower”). In July 2017, AES closed on the acquisition of its 48% ownership interest in sPower for $461 million. In November 2017, AES acquired an additional 2% ownership interest in sPower for $19 million. As the Company does not control sPower, it is accounted for as an equity method investment. The sPower portfolio includes solar and wind projects in operation, under construction, and in development located in the United States. The sPower equity method investment is reported in the US and Utilities SBU reportable segment.

AES Barry Ltd. — The Company holds a 100% ownership interest in AES Barry Ltd. ("Barry"), a dormant entity in the U.K. that disposed of its generation and other operating assets. Due to a debt agreement, no material financial or operating decisions can be made without the banks' consent, and the Company does not control Barry. As of December 31, 2018 and 2017, other long-term liabilities included $43 million and $45 million related to this debt agreement.

Summarized Financial Information — The following tables summarize financial information of the Company's 50%-or-less-owned affiliates and majority-owned unconsolidated subsidiaries that are accounted for using the equity method (in millions):

	50%-or-less Owned Affiliates			Majority-Owned Unconsolidated Subsidiaries		
Years ended December 31,	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Revenue	$ 962	$ 762	$ 586	$ 40	$ 16	$ 23
Operating margin	135	165	145	3	5	9
Net income (loss)	14	72	64	(3)	(15)	(2)
December 31,	**2018**	**2017**		**2018**	**2017**	
Current assets	$ 558	$ 418		$ 89	$ 70	
Noncurrent assets	5,918	5,372		41	102	
Current liabilities	546	633		35	10	
Noncurrent liabilities	3,309	2,629		122	147	
Stockholders' equity	2,622	2,527		(27)	15	

At December 31, 2018, retained earnings included $236 million related to the undistributed earnings of the Company's 50%-or-less owned affiliates. Distributions received from these affiliates were $42 million, $69 million, and $24 million for the years ended December 31, 2018, 2017, and 2016, respectively. As of December 31, 2018, the underlying equity in the net assets of our equity affiliates exceeded the aggregate carrying amount of our investments in equity affiliates by $49 million.

8. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill — The following table summarizes the carrying amount of goodwill by reportable segment for the years ended December 31, 2018 and 2017 (in millions):

	US and Utilities	South America	MCAC	Eurasia	Total
Balance as of December 31, 2017					
Goodwill	$ 2,786	$ 868	$ 16	$ 122	$ 3,792
Accumulated impairment losses	(2,611)	—	—	(122)	(2,733)
Net balance	175	868	16	—	1,059
Balance as of December 31, 2018					
Goodwill	2,786	868	16	122	3,792
Accumulated impairment losses	(2,611)	—	—	(122)	(2,733)
Net balance	$ 175	$ 868	$ 16	$ —	$ 1,059

Other Intangible Assets — The following table summarizes the balances comprising *Other intangible assets* in the accompanying Consolidated Balance Sheets (in millions) as of the periods indicated:

	December 31, 2018			December 31, 2017		
	Gross Balance	Accumulated Amortization	Net Balance	Gross Balance	Accumulated Amortization	Net Balance
Subject to Amortization						
Internal-use software	$ 467	$ (344)	$ 123	$ 416	$ (330)	$ 86
Contracts	137	(24)	113	92	(21)	71
Project development rights	93	(1)	92	57	(1)	56
Contractual payment rights (1)	57	(44)	13	65	(47)	18
Emissions allowances (2)	15	—	15	—	—	—
Other (3)	78	(44)	34	98	(42)	56
Subtotal	847	(457)	390	728	(441)	287
Indefinite-Lived Intangible Assets						
Land use rights	21	—	21	45	—	45
Water rights	20	—	20	20	—	20
Other	5	—	5	14	—	14
Subtotal	46	—	46	79	—	79
Total	$ 893	$ (457)	$ 436	$ 807	$ (441)	$ 366

(1) Represent legal rights to receive system reliability payments from the regulator.
(2) Acquired or purchased emissions allowances are finite-lived intangible assets that are expensed when utilized and included in net income for the year.
(3) Includes management rights, sales concessions, renewable energy credits and incentives, and other individually insignificant intangible assets. During the fourth quarter of 2018, the Company recognized an asset impairment of $23 million on gas extraction rights at Nejapa. See Note 20—*Asset Impairment Expense* for further information.

The following tables summarize other intangible assets acquired during the periods indicated (in millions):

December 31, 2018	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Internal-use software	$ 67	Subject to Amortization	6	Straight-line
Contracts	50	Subject to Amortization	24	Straight-line
Project development rights	35	Subject to Amortization	23	Straight-line
Emissions allowances	16	Subject to Amortization	Various	As utilized
Other	11	Various	N/A	N/A
Total	$ 179			

December 31, 2017	Amount	Subject to Amortization/ Indefinite-Lived	Weighted Average Amortization Period (in years)	Amortization Method
Project Development Rights	$ 53	Subject to Amortization	30	Straight-line
Contracts	34	Subject to Amortization	25	Straight-line
Internal-use software	17	Subject to Amortization	7	Straight-line
Other	8	Various	N/A	N/A
Total	$ 112			

The following table summarizes the estimated amortization expense by intangible asset category for 2019 through 2023:

(in millions)	2019	2020	2021	2022	2023
Internal-use software	$ 33	$ 28	$ 19	$ 13	$ 7
Contracts	4	4	4	4	4
Other	8	8	6	6	6
Total	$ 45	$ 40	$ 29	$ 23	$ 17

Intangible asset amortization expense was $47 million, $34 million and $37 million for the years ended December 31, 2018, 2017 and 2016, respectively.

9. REGULATORY ASSETS AND LIABILITIES

The Company has recorded regulatory assets and liabilities (in millions) that it expects to pass through to its customers in accordance with, and subject to, regulatory provisions as follows:

December 31,	2018	2017	Recovery/Refund Period
REGULATORY ASSETS			
Current regulatory assets:			
El Salvador energy pass through costs recovery	$ 87	$ 59	Quarterly
Other	69	60	Various
Total current regulatory assets	156	119	
Noncurrent regulatory assets:			
IPL and DPL defined benefit pension obligations [(1)]	283	298	Various
IPL deferred Midwest ISO costs	88	102	8 years
IPL environmental costs	89	48	Various
Other	87	94	Various
Total noncurrent regulatory assets	547	542	
TOTAL REGULATORY ASSETS	$ 703	$ 661	
REGULATORY LIABILITIES			
Current regulatory liabilities:			
Overcollection of costs to be passed back to customers	$ 83	$ 14	1 year
Other	3	3	Various
Total current regulatory liabilities	86	17	
Noncurrent regulatory liabilities:			
IPL and DPL accrued costs of removal and ARO's	847	830	Over life of assets
IPL and DPL income taxes payable to customers through rates	246	243	Various
Other	53	6	Various
Total noncurrent regulatory liabilities	1,146	1,079	
TOTAL REGULATORY LIABILITIES	$ 1,232	$ 1,096	

(1) Past expenditures on which the Company earns a rate of return.

Our regulatory assets primarily consist of costs that are generally non-controllable, such as purchased electricity, energy transmission, the difference between actual fuel costs and the fuel costs recovered in the tariffs, and other sector costs. These costs are recoverable or refundable as defined by the laws and regulations in our markets. Our regulatory assets also include defined pension and postretirement benefit obligations equal to the previously unrecognized actuarial gains and losses and prior services costs that are expected to be recovered through future rates. Other current and noncurrent regulatory assets primarily consist of:

- Demand charges at DPL;
- Unamortized premiums reacquired or redeemed on long-term debt at IPL and DPL, which are amortized over the lives of the original issuances; and
- Costs to comply with environmental regulations.

Our regulatory liabilities primarily consist of obligations for removal costs which do not have an associated legal retirement obligation. Our regulatory liabilities also include deferred income taxes associated with the reduction of the U.S. federal income tax rate which will be passed through to our regulated customers via a decrease in future retail rates, see Note 21—*Income Taxes* for further information.

In the accompanying Consolidated Balance Sheets the current regulatory assets and liabilities are reflected in *Other current assets* and *Accrued and other liabilities*, respectively, and the noncurrent regulatory assets and liabilities are reflected in *Other noncurrent assets* and *Other noncurrent liabilities*, respectively. The regulatory assets and liabilities primarily related to the US and Utilities SBU as of December 31, 2018 and December 31, 2017.

10. DEBT

NON-RECOURSE DEBT — The following table summarizes the carrying amount and terms of non-recourse debt at our subsidiaries as of the periods indicated (in millions):

NON-RECOURSE DEBT	Weighted Average Interest Rate	Maturity	December 31, 2018	December 31, 2017
Variable Rate:				
Bank loans	4.46%	2019 – 2050	$ 2,600	$ 2,488
Notes and bonds	3.89%	2020 – 2030	821	900
Debt to (or guaranteed by) multilateral, export credit agencies or development banks [1]	3.56%	2023 – 2034	3,292	3,668
Fixed Rate:				
Bank loans	4.62%	2019 – 2040	1,684	993
Notes and bonds	5.85%	2019 – 2073	7,346	7,388
Debt to (or guaranteed by) multilateral, export credit agencies or development banks [1]	5.45%	2023 – 2034	246	271
Other	5.87%	2023 – 2061	24	26
Unamortized (discount) premium & debt issuance (costs), net			(368)	(394)
Subtotal			$ 15,645	$ 15,340
Less: Current maturities			(1,659)	(2,164)
Noncurrent maturities			$ 13,986	$ 13,176

(1) Multilateral loans include loans funded and guaranteed by bilaterals, multilaterals, development banks and other similar institutions.

The interest rate on variable rate debt represents the total of a variable component that is based on changes in an interest rate index and of a fixed component. The Company has interest rate swaps and option agreements in an aggregate notional principal amount of approximately $3.9 billion on non-recourse debt outstanding at December 31, 2018. These agreements economically fix the variable component of the interest rates on the portion of the variable rate debt being hedged so that the total interest rate on that debt has been fixed at rates ranging from approximately 2.24% to 8.00%.

Non-recourse debt as of December 31, 2018 is scheduled to reach maturity as shown below (in millions):

December 31,	Annual Maturities
2019	$ 1,697
2020	1,458
2021	1,601
2022	1,530
2023	1,316
Thereafter	8,411
Unamortized (discount) premium & debt issuance (costs), net	(368)
Total	$ 15,645

As of December 31, 2018, AES subsidiaries with facilities under construction had a total of approximately $811 million of committed but unused credit facilities available to fund construction and other related costs. Excluding these facilities under construction, AES subsidiaries had approximately $1.8 billion in various unused committed credit lines to support their working capital, debt service reserves and other business needs. These credit lines can be used for borrowings, letters of credit, or a combination of these uses.

Significant transactions — During the year ended December 31, 2018, the Company's subsidiaries had the following significant debt transactions:

Subsidiary	Transaction Period	Issuances	Repayments	Gain (Loss) on Extinguishment of Debt
Southland [1]	Q1, Q2, Q3, Q4	$ 757	$ —	$ —
Tietê	Q1	385	(231)	—
Alto Maipo	Q2	104	—	—
DPL	Q2	—	(106)	(6)
Gener	Q3	—	(104)	(7)
Angamos	Q3	—	(98)	—
IPALCO	Q4	105	(89)	—
Total		$ 1,351	$ (628)	$ (13)

(1) Issuances relate to the June 2017, long-term non-recourse debt financing to fund the Southland re-powering construction projects.

AES Argentina — In February 2017, AES Argentina issued $300 million aggregate principal of unsecured and unsubordinated notes due in 2024. The net proceeds from this issuance were used for the prepayment of $75 million of non-recourse debt related to the construction of the San Nicolas Plant resulting in a gain on extinguishment of debt of approximately $65 million.

Non-Recourse Debt Covenants, Restrictions and Defaults — The terms of the Company's non-recourse debt include certain financial and nonfinancial covenants. These covenants are limited to subsidiary activity and vary among the subsidiaries. These covenants may include, but are not limited to, maintenance of certain reserves and financial ratios, minimum levels of working capital and limitations on incurring additional indebtedness.

As of December 31, 2018 and 2017, approximately $627 million and $642 million, respectively, of restricted cash was maintained in accordance with certain covenants of the non-recourse debt agreements, and these amounts were included within *Restricted cash* and *Debt service reserves and other deposits* in the accompanying Consolidated Balance Sheets.

Various lender and governmental provisions restrict the ability of certain of the Company's subsidiaries to transfer their net assets to the Parent Company. Such restricted net assets of subsidiaries amounted to approximately $2.9 billion at December 31, 2018.

The following table summarizes the Company's subsidiary non-recourse debt in default (in millions) as of December 31, 2018. Due to the defaults, these amounts are included in the current portion of non-recourse debt:

Subsidiary	Primary Nature of Default	December 31, 2018	
		Default	Net Assets
AES Puerto Rico	Covenant	$ 317	$ 139
AES Ilumina (Puerto Rico)	Covenant	34	17
Total		$ 351 [(1)]	

(1) This does not include $483 million of non-recourse debt at Colon, one of the Company's subsidiaries in Panama, that has been classified as current. Colon is currently in compliance with all provisions of its financing agreements, but does not expect to complete a required contract assignment to the lenders by the March 31, 2019 deadline. The Company is working with the lenders to modify the loan agreement to amend the requirement of this technical covenant in 2019. If this amendment is executed, the debt will be re-classified as noncurrent.

The above defaults are not payment defaults. All of the subsidiary non-recourse defaults were triggered by failure to comply with covenants and/or conditions such as (but not limited to) failure to meet information covenants, complete construction or other milestones in an allocated time, meet certain minimum or maximum financial ratios, or other requirements contained in the non-recourse debt documents of the applicable subsidiary.

The AES Corporation's recourse debt agreements include cross-default clauses that will trigger if a subsidiary or group of subsidiaries for which the non-recourse debt is in default provides more than 20% of the Parent Company's total cash distributions from businesses for the four most recently completed fiscal quarters. As of December 31, 2018, the Company has no defaults which result in or are at risk of triggering a cross-default under the recourse debt of the Parent Company. In the event the Parent Company is not in compliance with the financial covenants of its senior secured revolving credit facility, restricted payments will be limited to regular quarterly shareholder dividends at the then-prevailing rate. Payment defaults and bankruptcy defaults would preclude the making of any restricted payments.

RECOURSE DEBT — The following table summarizes the carrying amount and terms of recourse debt of the Company as of the periods indicated (in millions):

	Interest Rate	Final Maturity	December 31, 2018	December 31, 2017
Senior Unsecured Note	8.00%	2020	$ —	$ 228
Senior Unsecured Note	4.00%	2021	500	—
Senior Unsecured Note	7.38%	2021	—	690
Drawings on secured credit facility	LIBOR + 2.00%	2021	—	207
Senior Secured Term Loan	LIBOR + 1.75%	2022	366	521
Senior Unsecured Note	4.88%	2023	713	713
Senior Unsecured Note	4.50%	2023	500	—
Senior Unsecured Note	5.50%	2024	63	738
Senior Unsecured Note	5.50%	2025	544	573
Senior Unsecured Note	6.00%	2026	500	500
Senior Unsecured Note	5.13%	2027	500	500
Unamortized (discount) premium & debt issuance (costs), net			(31)	(40)
Subtotal			$ 3,655	$ 4,630
Less: Current maturities			(5)	(5)
Noncurrent maturities			$ 3,650	$ 4,625

The following table summarizes the principal amounts due under our recourse debt for the next five years and thereafter (in millions):

December 31,	Net Principal Amounts Due
2019	$ 5
2020	5
2021	505
2022	350
2023	1,213
Thereafter	1,608
Unamortized (discount) premium & debt issuance (costs), net	(31)
Total recourse debt	$ 3,655

In December 2018, the Company prepaid $150 million aggregate principal of its existing senior secured term loan due in 2022. As a result of the transaction, the Company recognized a loss on extinguishment of debt of $1 million.

In March 2018, the Company purchased via tender offers $671 million aggregate principal of its existing 5.50% senior unsecured notes due in 2024 and $29 million of its existing 5.50% senior unsecured notes due in 2025. As a result of these transactions, the Company recognized a loss on extinguishment of debt of $44 million.

In March 2018, the Company issued $500 million aggregate principal of 4.00% senior notes due in 2021 and $500 million of 4.50% senior notes due in 2023. The Company used the proceeds from these issuances to purchase via tender offer in full the $228 million balance of its 8.00% senior notes due in 2020 and the $690 million balance of its 7.375% senior notes due in 2021. As a result of these transactions, the Company recognized a loss on extinguishment of debt of $125 million.

In August 2017, the Company issued $500 million aggregate principal amount of 5.125% senior notes due in 2027. The Company used these proceeds to redeem at par $240 million aggregate principal of its existing LIBOR + 3.00% senior unsecured notes due in 2019 and purchased $217 million of its existing 8.00% senior unsecured notes due in 2020. As a result of the latter transactions, the Company recognized a loss on extinguishment of debt of $36 million.

In May 2017, the Company closed on $525 million aggregate principal LIBOR + 2.00% secured term loan due in 2022. In June 2017, the Company used these proceeds to redeem at par all $517 million aggregate principal of its existing Term Convertible Securities. As a result of the latter transaction, the Company recognized a loss on extinguishment of debt of $6 million.

In March 2017, the Company redeemed via tender offers $276 million aggregate principal of its existing 7.375% senior unsecured notes due in 2021 and $24 million of its existing 8.00% senior unsecured notes due in 2020. As a result of these transactions, the Company recognized a loss on extinguishment of debt of $47 million.

Recourse Debt Covenants and Guarantees — The Company's obligations under the senior secured credit facility and senior secured term loan are, subject to certain exceptions, secured by (i) all of the capital stock of domestic subsidiaries owned directly by the Company and 65% of the capital stock of certain foreign subsidiaries owned directly or indirectly by the Company; and (ii) certain intercompany receivables, certain intercompany notes and certain intercompany tax sharing agreements.

The senior secured credit facility and senior secured term loan are subject to mandatory prepayment under certain circumstances, including the sale of certain assets. In such a situation, the net cash proceeds from the sale must be applied pro rata to repay the term loan, if any, using 60% of net cash proceeds, reduced to 50% when and if the Parent Company's recourse debt to cash flow ratio is less than 5:1. The lenders have the option to waive their pro rata redemption.

The senior secured credit facility contains customary covenants and restrictions on the Company's ability to engage in certain activities, including, but not limited to, limitations on other indebtedness, liens, investments and guarantees; limitations on restricted payments such as shareholder dividends and equity repurchases; restrictions on mergers and acquisitions, sales of assets, leases, transactions with affiliates and off-balance sheet or derivative arrangements; and other financial reporting requirements.

The senior secured credit facility also contains financial covenants, evaluated quarterly, requiring the Company to maintain a minimum ratio of adjusted operating cash flow to interest charges on recourse debt of 1.3 times and a maximum ratio of recourse debt to adjusted operating cash flow of 7.5 times.

The terms of the Company's senior unsecured notes and senior secured term loan contain certain covenants including limitations on the Company's ability to incur liens or enter into sale and leaseback transactions.

TERM CONVERTIBLE TRUST SECURITIES — In 1999, AES Trust III, a wholly-owned special purpose business trust and a VIE, issued approximately 10.35 million of $50 par value TECONS with a quarterly coupon payment of $0.844 for total proceeds of $517 million and concurrently purchased $517 million of 6.75% Junior Subordinated Convertible Debentures due 2029 (the "6.75% Debentures") issued by AES. AES, at its option, may redeem the 6.75% Debentures which would result in the required redemption of the TECONS issued by AES Trust III for $50 per TECON. As of December 31, 2016, the sole assets of AES Trust III were the 6.75% Debentures. In June 2017, the Company redeemed the 6.75% Debentures and redeemed at par all remaining aggregate principal of its existing TECONs.

11. COMMITMENTS

LEASES — The Company enters into long-term non-cancelable lease arrangements which, for accounting purposes, are classified as either operating or capital leases. Operating leases primarily include certain transmission lines, office rental and site leases. Operating lease rental expense for the years ended December 31, 2018, 2017, and 2016 was $51 million, $61 million and $61 million, respectively. Capital leases primarily include transmission lines, vehicles, offices, and other operating equipment. Capital leases are recognized in Property, Plant and Equipment within *Electric generation, distribution assets and other*. The gross value of the capital lease assets as of December 31, 2018 and 2017 was $13 million and $27 million, respectively. The following table shows the future minimum lease payments under operating and capital leases for continuing operations together with the present value of the net minimum lease payments under capital leases as of December 31, 2018 for 2019 through 2023 and thereafter (in millions):

	Future Commitments for	
December 31,	**Capital Leases**	**Operating Leases**
2019	$ 1	$ 74
2020	1	38
2021	1	25
2022	1	26
2023	1	25
Thereafter	7	455
Total	$ 12	$ 643
Less: Imputed interest	(6)	
Present value of total minimum lease payments	$ 6	

CONTRACTS — The Company enters into long-term contracts for construction projects, maintenance and service, transmission of electricity, operations services and purchases of electricity and fuel. In general, these contracts are subject to variable quantities or prices and are terminable only in limited circumstances. The following table shows the future minimum commitments for continuing operations under these contracts as of December 31, 2018 for 2019 through 2023 and thereafter as well as actual purchases under these contracts for the years ended December 31, 2018, 2017, and 2016 (in millions):

Actual purchases during the year ended December 31,	Electricity Purchase Contracts	Fuel Purchase Contracts	Other Purchase Contracts
2016	$ 420	$ 1,790	$ 817
2017	747	1,619	1,945
2018	827	1,838	1,671
Future commitments for the year ending December 31,			
2019	$ 786	$ 1,494	$ 1,375
2020	602	1,027	681
2021	371	882	336
2022	234	575	561
2023	393	463	213
Thereafter	5,187	1,734	778
Total	$ 7,573	$ 6,175	$ 3,944

12. CONTINGENCIES

Guarantees and Letters of Credit — In connection with certain project financings, acquisitions and dispositions, power purchases and other agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. In the normal course of business, the Parent Company has entered into various agreements, mainly guarantees and letters of credit, to provide financial or performance assurance to third parties on behalf of AES businesses. These agreements are entered into primarily to support or enhance the creditworthiness otherwise achieved by a business on a stand-alone basis, thereby facilitating the availability of sufficient credit to accomplish their intended business purposes. Most of the contingent obligations relate to future performance commitments which the Company expects to fulfill within the normal course of business. The expiration dates of these guarantees vary from less than one year to more than 16 years.

The following table summarizes the Parent Company's contingent contractual obligations as of December 31, 2018. Amounts presented in the following table represent the Parent Company's current undiscounted exposure to guarantees and the range of maximum undiscounted potential exposure. The maximum exposure is not reduced by the amounts, if any, that could be recovered under the recourse or collateralization provisions in the guarantees. There were no obligations made by the Parent Company for the direct benefit of the lenders associated with the non-recourse debt of its businesses.

Contingent Contractual Obligations	Amount (in millions)	Number of Agreements	Maximum Exposure Range for Each Agreement (in millions)
Guarantees and commitments	$ 685	33	$0 — 157
Letters of credit under the unsecured credit facility	368	10	$1 — 247
Letters of credit under the senior secured credit facility	78	23	$0 — 49
Asset sale related indemnities [1]	27	1	$27
Total	$ 1,158	67	

(1) Excludes normal and customary representations and warranties in agreements for the sale of assets (including ownership in associated legal entities) where the associated risk is considered to be nominal.

During the year ended December 31, 2018, the Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts of letters of credit.

Environmental — The Company periodically reviews its obligations as they relate to compliance with environmental laws, including site restoration and remediation. For the periods ended December 31, 2018 and 2017, the Company had recognized liabilities of $5 million for projected environmental remediation costs. Due to the uncertainties associated with environmental assessment and remediation activities, future costs of compliance or remediation could be higher or lower than the amount currently accrued. Moreover, where no liability has been recognized, it is reasonably possible that the Company may be required to incur remediation costs or make expenditures in amounts that could be material but could not be estimated as of December 31, 2018. In aggregate, the Company estimates the range of potential losses related to environmental matters, where estimable, to be up to $17 million. The amounts considered reasonably possible do not include amounts accrued as discussed above.

Litigation — The Company is involved in certain claims, suits and legal proceedings in the normal course of business. The Company accrues for litigation and claims when it is probable that a liability has been incurred and the amount of loss can be reasonably estimated. The Company has recognized aggregate liabilities for all claims of approximately $53 million and $50 million as of December 31, 2018 and 2017, respectively. These amounts are reported on the Consolidated Balance Sheets within *Accrued and other liabilities* and *Other noncurrent liabilities*. A significant portion of these accrued liabilities relate to regulatory matters and commercial disputes in international jurisdictions. There can be no assurance that these accrued liabilities will be adequate to cover all existing and future claims or that we will have the liquidity to pay such claims as they arise.

Where no accrued liability has been recognized, it is reasonably possible that some matters could be decided unfavorably to the Company and could require the Company to pay damages or make expenditures in amounts that could be material but could not be estimated as of December 31, 2018. The material contingencies where a loss is reasonably possible primarily include disputes with offtakers, suppliers and EPC contractors; alleged breaches of contract; alleged violation of laws and regulations; income tax and non-income tax matters with tax authorities; and regulatory matters. In aggregate, the Company estimates the range of potential losses, where estimable, related to these reasonably possible material contingencies to be between $79 million and $439 million. The amounts considered reasonably possible do not include amounts accrued, as discussed above. These material contingencies do not include income tax-related contingencies which are considered part of our uncertain tax positions.

13. BENEFIT PLANS

Defined Contribution Plan — The Company sponsors four defined contribution plans ("the DC Plans"). Two plans cover U.S. non-union employees; one for Parent Company and certain US and Utilities SBU business employees, and one for DPL employees. The remaining two plans include union and non-union employees at IPL and union employees at DPL. The DC Plans are qualified under section 401 of the Internal Revenue Code. Most U.S. employees of the Company are eligible to participate in the appropriate plan except for those employees who are covered by a collective bargaining agreement, unless such agreement specifically provides that the employee is considered an eligible employee under a plan. Within the DC Plans, the Company provides matching contributions in addition to other non-matching contributions. Participants are fully vested in their own contributions. The Company's contributions vest over various time periods ranging from immediate up to five years. For the years ended December 31, 2018, 2017 and 2016, costs for defined contribution plans were approximately $21 million, $23 million and $15 million, respectively.

Defined Benefit Plans — Certain of the Company's subsidiaries have defined benefit pension plans covering substantially all of their respective employees ("the DB Plans"). Pension benefits are based on years of credited service, age of the participant, and average earnings. Of the 30 active DB Plans as of December 31, 2018, five are at U.S. subsidiaries and the remaining plans are at foreign subsidiaries.

The following table reconciles the Company's funded status, both domestic and foreign, as of the periods indicated (in millions):

	2018		2017	
	U.S.	Foreign	U.S.	Foreign
CHANGE IN PROJECTED BENEFIT OBLIGATION:				
Benefit obligation as of January 1	$ 1,257	$ 470	$ 1,188	$ 411
Service cost	15	12	13	10
Interest cost	40	22	41	22
Employee contributions	—	1	—	1
Plan amendments	10	—	1	(1)
Plan curtailments	—	—	3	—
Plan settlements	—	(21)	—	(2)
Benefits paid	(105)	(17)	(71)	(22)
Plan combinations	—	(4)	—	—
Actuarial (gain) loss	(99)	(8)	82	29
Effect of foreign currency exchange rate changes	—	(38)	—	22
Benefit obligation as of December 31	$ 1,118	$ 417	$ 1,257	$ 470
CHANGE IN PLAN ASSETS:				
Fair value of plan assets as of January 1	$ 1,127	$ 455	$ 1,044	$ 402
Actual return on plan assets	(35)	6	141	31
Employer contributions	39	21	13	18
Employee contributions	—	1	—	1
Plan settlements	—	(21)	—	(2)
Benefits paid	(105)	(17)	(71)	(22)
Effect of foreign currency exchange rate changes	—	(35)	—	27
Fair value of plan assets as of December 31	$ 1,026	$ 410	$ 1,127	$ 455
RECONCILIATION OF FUNDED STATUS				
Funded status as of December 31	$ (92)	$ (7)	$ (130)	$ (15)

The following table summarizes the amounts recognized on the Consolidated Balance Sheets related to the funded status of the DB Plans, both domestic and foreign, as of the periods indicated (in millions):

December 31,	2018		2017	
Amounts Recognized on the Consolidated Balance Sheets	U.S.	Foreign	U.S.	Foreign
Noncurrent assets	$ —	$ 64	$ —	$ 69
Accrued benefit liability—current	—	(6)	—	(6)
Accrued benefit liability—noncurrent	(92)	(65)	(130)	(78)
Net amount recognized at end of year	$ (92)	$ (7)	$ (130)	$ (15)

The following table summarizes the Company's U.S. and foreign accumulated benefit obligation as of the periods indicated (in millions):

December 31,	2018		2017	
	U.S.	Foreign	U.S.	Foreign
Accumulated Benefit Obligation	$ 1,101	$ 376	$ 1,236	$ 433
Information for pension plans with an accumulated benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 1,118	$ 89	$ 1,257	$ 109
Accumulated benefit obligation	1,101	79	1,236	97
Fair value of plan assets	1,026	33	1,127	33
Information for pension plans with a projected benefit obligation in excess of plan assets:				
Projected benefit obligation	$ 1,118	$ 220	$ 1,257	$ 238
Fair value of plan assets	1,026	150	1,127	154

The following table summarizes the significant weighted average assumptions used in the calculation of benefit obligation and net periodic benefit cost, both domestic and foreign, as of the periods indicated:

December 31,		2018		2017	
		U.S.	Foreign	U.S.	Foreign
Benefit Obligation:	Discount rate	4.35%	5.63%	3.67%	5.23%
	Rate of compensation increase	3.34%	4.79%	3.34%	4.65%
Periodic Benefit Cost:	Discount rate	3.67%	5.23% (1)	4.28%	5.83% (1)
	Expected long-term rate of return on plan assets	5.73%	3.94%	6.67%	5.30%
	Rate of compensation increase	3.34%	4.65%	3.34%	4.86%

(1) Includes an inflation factor that is used to calculate future periodic benefit cost, but is not used to calculate the benefit obligation.

The Company establishes its estimated long-term return on plan assets considering various factors, which include the targeted asset allocation percentages, historic returns, and expected future returns.

The measurement of pension obligations, costs, and liabilities is dependent on a variety of assumptions. These assumptions include estimates of the present value of projected future pension payments to all plan participants, taking into consideration the likelihood of potential future events such as salary increases and demographic experience. These assumptions may have an effect on the amount and timing of future contributions.

The assumptions used in developing the required estimates include the following key factors: discount rates; salary growth; retirement rates; inflation; expected return on plan assets; and mortality rates. The effects of actual results differing from the Company's assumptions are accumulated and amortized over future periods and, therefore, generally affect the Company's recognized expense in such future periods. Unrecognized gains or losses are amortized using the “corridor approach,” under which the net gain or loss in excess of 10% of the greater of the projected benefit obligation or the market-related value of the assets, if applicable, is amortized.

Sensitivity of the Company's pension funded status to the indicated increase or decrease in the discount rate and long-term rate of return on plan assets assumptions is shown below. Note that these sensitivities may be asymmetric and are specific to the base conditions at year-end 2018. They also may not be additive, so the impact of changing multiple factors simultaneously cannot be calculated by combining the individual sensitivities shown. The funded status as of December 31, 2018 is affected by the assumptions as of that date. Pension expense for 2018 is affected by the December 31, 2017 assumptions. The impact on pension expense from a one percentage point change in these assumptions is shown in the following table (in millions):

Increase of 1% in the discount rate	$ (12)
Decrease of 1% in the discount rate	12
Increase of 1% in the long-term rate of return on plan assets	(16)
Decrease of 1% in the long-term rate of return on plan assets	16

The following table summarizes the components of the net periodic benefit cost, both domestic and foreign, for the years indicated (in millions):

December 31,	2018		2017		2016	
Components of Net Periodic Benefit Cost:	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Service cost	$ 15	$ 12	$ 13	$ 10	$ 13	$ 9
Interest cost	40	22	41	23	42	21
Expected return on plan assets	(64)	(17)	(69)	(21)	(68)	(19)
Amortization of prior service cost	5	—	6	—	7	(1)
Amortization of net loss	18	3	18	2	18	2
Curtailment loss recognized	1	—	4	—	4	—
Settlement loss recognized	—	4	—	—	—	—
Total pension cost	$ 15	$ 24	$ 13	$ 14	$ 16	$ 12

The following table summarizes the amounts reflected in AOCL, including AOCL attributable to noncontrolling interests, on the Consolidated Balance Sheet as of December 31, 2018, that have not yet been recognized as components of net periodic benefit cost (in millions):

December 31, 2018	Accumulated Other Comprehensive Income (Loss)	
	U.S.	Foreign
Prior service cost	$ (4)	$ 1
Unrecognized net actuarial loss	(19)	(76)
Total	$ (23)	$ (75)

The following table summarizes the Company's target allocation for 2018 and pension plan asset allocation, both domestic and foreign, as of the periods indicated:

	Target Allocations		Percentage of Plan Assets as of December 31,			
			2018		2017	
Asset Category	U.S.	Foreign	U.S.	Foreign	U.S.	Foreign
Equity securities	20%	3%	16.85%	3.75%	31.90%	4.61%
Debt securities	78%	94%	80.20%	93.57%	64.53%	93.10%
Real estate	2%	—%	2.35%	0.44%	3.20%	0.44%
Other	—%	3%	0.60%	2.24%	0.37%	1.85%
Total pension assets			100.00%	100.00%	100.00%	100.00%

The U.S. DB Plans seek to achieve the following long-term investment objectives:

- maintenance of sufficient income and liquidity to pay retirement benefits and other lump sum payments;
- long-term rate of return in excess of the annualized inflation rate;
- long-term rate of return, net of relevant fees, that meets or exceeds the assumed actuarial rate; and
- long-term competitive rate of return on investments, net of expenses, that equals or exceeds various benchmark rates.

The asset allocation is reviewed periodically to determine a suitable asset allocation which seeks to manage risk through portfolio diversification and takes into account the above-stated objectives, in conjunction with current funding levels, cash flow conditions and economic and industry trends. The following table summarizes the Company's U.S. DB Plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2018				December 31, 2017			
U.S. Plans		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Equity securities:	Mutual funds	$ 173	$ —	$ —	$ 173	$ 359	$ —	$ —	$ 359
Debt securities:	Government debt securities	170	—	—	170	135	—	—	135
	Mutual funds [1]	653	—	—	653	593	—	—	593
Real estate:	Real estate	—	24	—	24	—	36	—	36
Other:	Cash and cash equivalents	6	—	—	6	4	—	—	4
	Total plan assets	$ 1,002	$ 24	$ —	$ 1,026	$ 1,091	$ 36	$ —	$ 1,127

[1] Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.

The investment strategy of the foreign DB Plans seeks to maximize return on investment while minimizing risk. The assumed asset allocation has less exposure to equities in order to closely match market conditions and near term forecasts. The following table summarizes the Company's foreign DB plan assets by category of investment and level within the fair value hierarchy as of the periods indicated (in millions):

		December 31, 2018				December 31, 2017			
Foreign Plans		Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Equity securities:	Mutual funds	$ 14	$ —	$ —	$ 14	$ 20	$ —	$ —	$ 20
	Private equity	—	—	1	1	—	—	1	1
Debt securities:	Government debt securities	13	—	—	13	11	—	—	11
	Mutual funds [1]	287	84	—	371	323	90	—	413
Real estate:	Real estate	—	—	2	2	—	—	2	2
Other:	Cash and cash equivalents	2	—	—	2	—	—	—	—
	Other assets	1	—	6	7	1	—	7	8
	Total plan assets	$ 317	$ 84	$ 9	$ 410	$ 355	$ 90	$ 10	$ 455

[1] Mutual funds categorized as debt securities consist of mutual funds for which debt securities are the primary underlying investment.

The following table summarizes the estimated cash flows for U.S. and foreign expected employer contributions and expected future benefit payments, both domestic and foreign (in millions):

	U.S.	Foreign
Expected employer contribution in 2019	$ 9	$ 14
Expected benefit payments for fiscal year ending:		
2019	69	23
2020	70	21
2021	72	23
2022	72	24
2023	73	25
2024 - 2028	367	155

14. EQUITY

Equity Transactions with Noncontrolling Interests

Distributed Energy — In 2018, Distributed Energy, through multiple transactions, sold noncontrolling interests in multiple project companies to tax equity partners. These transactions resulted in a $98 million increase to noncontrolling interest. Distributed Energy is reported in the US and Utilities SBU reportable segment.

Alto Maipo — In March 2017, AES Gener completed the legal and financial restructuring of Alto Maipo. As part of this restructuring, AES indirectly acquired the 40% ownership interest of the noncontrolling shareholder for a de minimis payment, and sold a 6.7% interest in the project to the construction contractor. This transaction resulted in a $196 million increase to the Parent Company's Stockholders' Equity due to an increase in additional paid-in-capital of $229 million, offset by the reclassification of accumulated other comprehensive losses from NCI to the Parent Company Stockholders' Equity of $33 million. No gain or loss was recognized in net income as the sale was not considered to be a sale of in-substance real estate. After completion of the sale, the Company has an effective 62% economic interest in Alto Maipo. As the Company maintained control of the partnership after the sale, Alto Maipo continues to be consolidated by the Company within the South America SBU reportable segment.

Dominican Republic — In September 2017, Linda Group acquired 5% of our Dominican Republic business for $60 million, pre-tax. This transaction resulted in a net increase of $25 million to the Company's additional paid-in-capital and noncontrolling interest, respectively. No gain or loss was recognized in net income as the sale was not considered a sale of in-substance real estate. As the Company maintained control after the sale, our businesses in the Dominican Republic continue to be consolidated by the Company within the MCAC SBU reportable segment.

The following table summarizes the net income attributable to The AES Corporation and all transfers (to) from noncontrolling interests for the periods indicated (in millions):

	December 31,		
	2018	2017	2016
Net income (loss) attributable to The AES Corporation	$ 1,203	$ (1,161)	$ (1,130)
Transfers from noncontrolling interest:			
Increase (decrease) in The AES Corporation's paid-in capital for sale of subsidiary shares	(3)	13	84
Additional paid-in-capital, IPALCO shares, transferred to redeemable stock of subsidiaries (1)	—	—	(84)
Increase (decrease) in The AES Corporation's paid-in-capital for purchase of subsidiary shares	—	240	(2)
Net transfers (to) from noncontrolling interest	(3)	253	(2)
Change from net income (loss) attributable to The AES Corporation and transfers (to) from noncontrolling interests	$ 1,200	$ (908)	$ (1,132)

(1) See Note 17—*Redeemable stock of subsidiaries* for further information on increase in paid-in-capital transferred to redeemable stock of subsidiaries.

Accumulated Other Comprehensive Loss — The changes in AOCL by component, net of tax and noncontrolling interests, for the periods indicated were as follows (in millions):

	Foreign currency translation adjustment, net	Derivative gains (losses), net	Unfunded pension obligations, net	Total
Balance at December 31, 2016	$ (2,147)	$ (323)	$ (286)	$ (2,756)
Other comprehensive income (loss) before reclassifications	18	(14)	(19)	(15)
Amount reclassified to earnings	643	37	248	928
Other comprehensive income	$ 661	$ 23	$ 229	$ 913
Reclassification from NCI due to Alto Maipo Restructuring	—	(33)	—	(33)
Balance at December 31, 2017	$ (1,486)	$ (333)	$ (57)	$ (1,876)
Other comprehensive income (loss) before reclassifications	$ (214)	$ (64)	$ —	$ (278)
Amount reclassified to earnings	(21)	78	7	64
Other comprehensive income (loss)	$ (235)	$ 14	$ 7	$ (214)
Cumulative effect of a change in accounting principle	—	19	—	19
Balance at December 31, 2018	$ (1,721)	$ (300)	$ (50)	$ (2,071)

Reclassifications out of AOCL are presented in the following table. Amounts for the periods indicated are in millions and those in parenthesis indicate debits to the Consolidated Statements of Operations:

Details About AOCL Components	Affected Line Item in the Consolidated Statements of Operations	December 31, 2018	2017	2016
Foreign currency translation adjustments, net				
	Gain (loss) on disposal and sale of business interests	$ 19	$ (188)	$ —
	Net loss from disposal and impairments of discontinued operations	2	(455)	(992)
	Net income (loss) attributable to The AES Corporation	$ 21	$ (643)	$ (992)
Derivative gains (losses), net				
	Non-regulated revenue	$ (6)	$ 25	$ 111
	Non-regulated cost of sales	(3)	(12)	(57)
	Interest expense	(49)	(79)	(107)
	Foreign currency transaction gains	(59)	15	8
	Income from continuing operations before taxes and equity in earnings of affiliates	(117)	(51)	(45)
	Income tax expense	24	1	8
	Income (loss) from continuing operations	(93)	(50)	(37)
	Less: (Income) loss from continuing operations attributable to noncontrolling interests	15	13	9
	Net income (loss) attributable to The AES Corporation	$ (78)	$ (37)	$ (28)
Amortization of defined benefit pension actuarial losses, net				
	Non-regulated cost of sales	—	1	—
	General and administrative expenses	—	(1)	(1)
	Other expense	(6)	—	(1)
	Income from continuing operations before taxes and equity in earnings of affiliates	(6)	—	(2)
	Income tax expense	2	—	3
	Income from continuing operations	(4)	—	1
	Net loss from disposal and impairments of discontinued operations	(2)	(266)	(11)
	Net income (loss)	(6)	(266)	(10)
	Less: (Income) loss from continuing operations attributable to noncontrolling interests	(1)	—	9
	Add: Loss from discontinued operations attributable to noncontrolling interests	—	18	—
	Net income (loss) attributable to The AES Corporation	$ (7)	$ (248)	$ (1)
Total reclassifications for the period, net of income tax and noncontrolling interests		$ (64)	$ (928)	$ (1,021)

Common Stock Dividends — The Parent Company paid dividends of $0.13 per outstanding share to its common stockholders during the first, second, third and fourth quarters of 2018 for dividends declared in December 2017, February, July and October 2018, respectively.

On December 7, 2018, the Board of Directors declared a quarterly common stock dividend of $0.1365 per share payable on February 15, 2019 to shareholders of record at the close of business on February 1, 2019.

Stock Repurchase Program — No shares were repurchased in 2018. The cumulative repurchases from the commencement of the Program in July 2010 through December 31, 2018 totaled 154.3 million shares for a total cost of $1.9 billion, at an average price per share of $12.12 (including a nominal amount of commissions). As of December 31, 2018, $264 million remained available for repurchase under the Program.

The common stock repurchased has been classified as treasury stock and accounted for using the cost method. A total of 154,905,595 and 155,924,785 shares were held as treasury stock at December 31, 2018 and 2017, respectively. Restricted stock units under the Company's employee benefit plans are issued from treasury stock. The Company has not retired any common stock repurchased since it began the Program in July 2010.

15. SEGMENTS AND GEOGRAPHIC INFORMATION

The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally and is mainly organized by geographic regions which provides a socio-political-economic understanding of our business. During the first quarter of 2018, the Andes and Brazil SBUs were merged in order to leverage scale and are now reported together as part of the South America SBU. Further, the Puerto Rico and El Salvador businesses, formerly part of the MCAC SBU, were combined with the US SBU, which is now reported as the US and Utilities SBU. The management reporting structure is organized by four SBUs led by our President and Chief Executive Officer: US and Utilities, South America, MCAC, and Eurasia SBUs. Using the accounting guidance on segment reporting, the Company determined that its four operating segments are aligned with its four reportable segments corresponding to its SBUs. All prior period results have been retrospectively revised to reflect the new segment reporting structure.

Corporate and Other — The results of the Fluence and Simple Energy equity affiliates are included in "Corporate and Other". Also included are the results of the AES self-insurance company and corporate overhead costs which are not directly associated with the operations of our four reportable segments, and certain intercompany charges such as self-insurance premiums which are fully eliminated in consolidation.

The Company uses Adjusted PTC as its primary segment performance measure. Adjusted PTC, a non-GAAP measure, is defined by the Company as pre-tax income from continuing operations attributable to The AES Corporation excluding gains or losses of the consolidated entity due to (a) unrealized gains or losses related to derivative transactions and equity securities; (b) unrealized foreign currency gains or losses; (c) gains, losses, benefits and costs associated with dispositions and acquisitions of business interests, including early plant closures; (d) losses due to impairments; (e) gains, losses and costs due to the early retirement of debt; and (f) costs directly associated with a major restructuring program, including, but not limited to, workforce reduction efforts, relocations and office consolidation. Adjusted PTC also includes net equity in earnings of affiliates on an after-tax basis adjusted for the same gains or losses excluded from consolidated entities. The Company has concluded Adjusted PTC better reflects the underlying business performance of the Company and is the most relevant measure considered in the Company's internal evaluation of the financial performance of its segments. Additionally, given its large number of businesses and complexity, the Company concluded that Adjusted PTC is a more transparent measure that better assists investors in determining which businesses have the greatest impact on the Company's results.

Revenue and Adjusted PTC are presented before inter-segment eliminations, which includes the effect of intercompany transactions with other segments except for interest, charges for certain management fees, and the write-off of intercompany balances, as applicable. All intra-segment activity has been eliminated within the segment. Inter-segment activity has been eliminated within the total consolidated results.

The following tables present financial information by segment for the periods indicated (in millions):

	Total Revenue		
Year Ended December 31,	**2018**	**2017**	**2016**
US and Utilities SBU	$ 4,230	$ 4,162	$ 4,330
South America SBU	3,533	3,252	2,956
MCAC SBU	1,728	1,519	1,274
Eurasia SBU	1,255	1,590	1,670
Corporate and Other	41	35	77
Eliminations	(51)	(28)	(26)
Total Revenue	$ 10,736	$ 10,530	$ 10,281

Reconciliation from Income from Continuing Operations before Taxes and Equity in Earnings of Affiliates:	Total Adjusted PTC		
Year Ended December 31,	**2018**	**2017**	**2016**
Income from continuing operations before taxes and equity in earnings of affiliates	$ 2,018	$ 771	$ 187
Add: Net equity earnings in affiliates	39	71	36
Less: Income from continuing operations before taxes, attributable to noncontrolling interests	(509)	(521)	(354)
Pre-tax contribution	1,548	321	(131)
Unrealized derivative losses (gains)	33	(3)	(9)
Unrealized foreign currency losses (gains)	51	(59)	22
Disposition/acquisition losses (gains)	(934)	123	6
Impairment expense	307	542	933
Loss on extinguishment of debt	180	62	29
Restructuring costs	—	31	—
Total Adjusted PTC	$ 1,185	$ 1,017	$ 850

	Total Adjusted PTC		
Year Ended December 31,	**2018**	**2017**	**2016**
US and Utilities SBU	$ 511	$ 424	$ 392
South America SBU	519	446	428
MCAC SBU	300	277	222
Eurasia SBU	222	290	283
Corporate, Other and Eliminations	(367)	(420)	(475)
Total Adjusted PTC	$ 1,185	$ 1,017	$ 850

	Total Assets			Depreciation and Amortization			Capital Expenditures		
Year Ended December 31,	2018	2017	2016	2018	2017	2016	2018	2017	2016
US and Utilities SBU	$ 12,286	$ 11,548	$ 10,815	$ 449	$ 487	$ 519	$ 1,373	$ 905	$ 858
South America SBU	10,941	11,126	10,487	300	301	251	662	477	569
MCAC SBU	4,462	4,087	3,680	141	122	117	302	435	431
Eurasia SBU	4,538	6,002	5,777	99	127	149	51	211	279
Discontinued operations	—	86	4,936	—	123	128	—	315	303
Corporate, Other and Eliminations	294	263	429	14	9	12	8	13	18
Total	$ 32,521	$ 33,112	$ 36,124	$ 1,003	$ 1,169	$ 1,176	$ 2,396	$ 2,356	$ 2,458

	Interest Income			Interest Expense		
Year Ended December 31,	2018	2017	2016	2018	2017	2016
US and Utilities SBU	$ 10	$ 5	$ 4	$ 287	$ 315	$ 299
South America SBU	92	95	95	283	297	247
MCAC SBU	20	13	7	124	111	100
Eurasia SBU	186	130	139	145	167	179
Corporate, Other and Eliminations	2	1	—	217	280	309
Total	$ 310	$ 244	$ 245	$ 1,056	$ 1,170	$ 1,134

	Investments in and Advances to Affiliates			Net Equity in Earnings of Affiliates		
Year Ended December 31,	2018	2017	2016	2018	2017	2016
US and Utilities SBU	$ 538	$ 535	$ 23	$ 35	$ 41	$ 9
South America SBU	213	358	363	15	28	15
MCAC SBU	5	(5)	(1)	(7)	(4)	(2)
Eurasia SBU	293	307	236	14	9	13
Corporate, Other and Eliminations	65	2	—	(18)	(3)	1
Total	$ 1,114	$ 1,197	$ 621	$ 39	$ 71	$ 36

The following table presents information, by country, about the Company's consolidated operations for each of the three years ended December 31, 2018, 2017, and 2016, and as of December 31, 2018 and 2017 (in millions). Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Total Revenue			Property, Plant & Equipment, net	
Year Ended December 31,	2018	2017	2016	2018	2017
United States [(1)]	$ 3,462	$ 3,487	$ 3,790	$ 8,731	$ 7,968
Non-U.S.:					
Chile	2,087	1,944	1,707	5,453	5,066
Dominican Republic	884	826	614	903	935
El Salvador	768	686	601	334	340
Brazil	527	541	450	1,287	1,286
Argentina	487	435	359	234	223
Panama	438	338	312	1,777	1,615
Colombia	428	332	437	302	332
Bulgaria	426	367	334	1,183	1,290
Mexico	399	352	342	666	687
United Kingdom	390	328	337	90	108
Vietnam [(2)]	245	278	340	2	2
Jordan	95	95	136	418	431
Philippines [(3)]	93	449	401	—	—
Kazakhstan	—	67	103	—	—
Other Non-U.S.	7	5	18	16	13
Total Non-U.S.	7,274	7,043	6,491	12,665	12,328
Total	$ 10,736	$ 10,530	$ 10,281	$ 21,396	$ 20,296

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(1) Includes Puerto Rico revenues of $257 million, $247 million and $301 million for the years ended December 31, 2018, 2017 and 2016, respectively, and property, plant & equipment of $553 million and $565 million as of December 31, 2018 and 2017, respectively.

(2) The Mong Duong II power project is operated under a build, operate and transfer contract. Future expected payments for the construction performance obligation are recognized in *Loan receivable* on the Consolidated Balance Sheets. See Note 18—*Revenue* for further information.

(3) The Masinloc property, plant and equipment was classified as held-for-sale as of December 31, 2017, and deconsolidated upon completion of the sale in March 2018. See Note 23—*Held-For-Sale and Dispositions* for further information.

16. SHARE-BASED COMPENSATION

RESTRICTED STOCK

Restricted Stock Units — The Company issues RSUs under its long-term compensation plan. The RSUs are generally granted based upon a percentage of the participant's base salary. The units have a three-year vesting schedule and vest in one-third increments over the three-year period. In all circumstances, RSUs granted by AES do not entitle the holder the right, or obligate AES, to settle the RSU in cash or other assets of AES.

For the years ended December 31, 2018, 2017, and 2016, RSUs issued had a grant date fair value equal to the closing price of the Company's stock on the grant date. The Company does not discount the grant date fair values to reflect any post-vesting restrictions. RSUs granted to employees during the years ended December 31, 2018, 2017, and 2016 had grant date fair values per RSU of $10.55, $11.93 and $9.42, respectively.

The following table summarizes the components of the Company's stock-based compensation related to its employee RSUs recognized in the Company's consolidated financial statements (in millions):

December 31,	2018	2017	2016
RSU expense before income tax	$ 11	$ 17	$ 14
Tax benefit	(2)	(4)	(4)
RSU expense, net of tax	$ 9	$ 13	$ 10
Total value of RSUs converted [1]	$ 10	$ 10	$ 7
Total fair value of RSUs vested	$ 16	$ 15	$ 13

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(1) Amount represents fair market value on the date of conversion.

Cash was not used to settle RSUs or compensation cost capitalized as part of the cost of an asset for the years ended December 31, 2018, 2017, and 2016. As of December 31, 2018, total unrecognized compensation cost related to RSUs of $10 million is expected to be recognized over a weighted average period of approximately 1.7 years. There were no modifications to RSU awards during the year ended December 31, 2018.

A summary of the activity of RSUs for the year ended December 31, 2018 follows (RSUs in thousands):

	RSUs	Weighted Average Grant Date Fair Values	Weighted Average Remaining Vesting Term
Nonvested at December 31, 2017	2,966	$ 11.02	
Vested	(1,428)	11.05	
Forfeited and expired	(528)	10.95	
Granted	913	10.55	
Nonvested at December 31, 2018	1,923	$ 10.80	1.4
Vested and expected to vest at December 31, 2018	1,782	$ 10.79	

The Company initially recognizes compensation cost on the estimated number of instruments for which the requisite service is expected to be rendered. In 2018, AES has estimated a weighted average forfeiture rate of 9.35% for RSUs granted in 2018. This estimate will be revised if subsequent information indicates that the actual number of instruments forfeited is likely to differ from previous estimates. Based on the estimated forfeiture rate, the Company expects to expense $9 million on a straight-line basis over a three-year period.

The following table summarizes the RSUs that vested and were converted during the periods indicated (RSUs in thousands):

Year Ended December 31,	2018	2017	2016
RSUs vested during the year	1,428	1,337	1,063
RSUs converted during the year, net of shares withheld for taxes	950	865	705
Shares withheld for taxes	478	472	358

OTHER SHARE BASED COMPENSATION

The Company has three other share-based award programs. The Company has recorded expenses of $20 million, $8 million and $10 million for 2018, 2017 and 2016, respectively, related to these programs.

Stock options — AES grants options to purchase shares of common stock under stock option plans to non-employee directors. Under the terms of the plans, the Company may issue options to purchase shares of the Company's common stock at a price equal to 100% of the market price at the date the option is granted. Stock options issued in 2017 and 2018 have a three-year vesting schedule and vest in one-third increments over the three-year period. The stock options have a contractual term of 10 years. In all circumstances, stock options granted by AES do not entitle the holder the right, or obligate AES, to settle the stock option in cash or other assets of AES.

Performance Stock Units — In 2016, 2017 and 2018, the Company issued PSUs to officers under its long-term compensation plan. PSUs are stock units which include performance conditions. Performance conditions are based on the Company's Proportional Free Cash Flow targets for 2016, 2017 and 2018. The performance conditions determine the vesting and final share equivalent per PSU and can result in earning an award payout range of 0% to 200%, depending on the achievement. The Company believes that it is probable that the performance condition will be met and will continue to be evaluated throughout the performance period. In all circumstances, PSUs granted by AES do not entitle the holder the right, or obligate AES, to settle the stock units in cash or other assets of AES.

Performance Cash Units — In 2016, 2017 and 2018, the Company issued PCUs to its officers under its long-term compensation plan. The value of these units is dependent on the market condition of total stockholder return on AES common stock as compared to the total stockholder return of the Standard and Poor's 500 Utilities Sector Index, Standard and Poor's 500 Index and MSCI Emerging Market Index over a three-year measurement period. Since PCUs are settled in cash, they qualify for liability accounting and periodic measurement is required.

17. REDEEMABLE STOCK OF SUBSIDIARIES

The following table is a reconciliation of changes in redeemable stock of subsidiaries (in millions):

December 31,	2018	2017
Balance at the beginning of the period	$ 837	$ 782
Contributions from holders of redeemable stock of subsidiaries	34	50
Net income (loss) attributable to redeemable stock of subsidiaries	2	(14)
Fair value adjustment	4	25
Other comprehensive income (loss) attributable to redeemable stock of subsidiaries	2	(2)
Acquisition and reclassification of stock of subsidiaries	—	(4)
Balance at the end of the period	$ 879	$ 837

The following table summarizes the Company's redeemable stock of subsidiaries balances as of the periods indicated (in millions):

December 31,	2018	2017
IPALCO common stock	$ 618	$ 618
Colon quotas (1)	201	159
IPL preferred stock	60	60
Total redeemable stock of subsidiaries	$ 879	$ 837

(1) Characteristics of quotas are similar to common stock.

Colon — Our partner in Colon made capital contributions of $34 million and $50 million during the year ended December 31, 2018 and 2017, respectively. Any subsequent adjustments to allocate earnings and dividends to our partner, or measure the investment at fair value, will be classified as temporary equity each reporting period as it is probable that the shares will become redeemable.

IPL — IPL had $60 million of cumulative preferred stock outstanding at December 31, 2018 and 2017, which represent five series of preferred stock. The total annual dividend requirements were approximately $3 million at December 31, 2018 and 2017. Certain series of the preferred stock were redeemable solely at the option of the issuer at prices between $100 and $118 per share. Holders of the preferred stock are entitled to elect a majority of IPL's board of directors if IPL has not paid dividends to its preferred stockholders for four consecutive quarters. Based on the preferred stockholders' ability to elect a majority of IPL's board of directors in this circumstance, the redemption of the preferred shares is considered to be not solely within the control of the issuer and the preferred stock is considered temporary equity.

IPALCO — As part of a purchase agreement executed in 2014, CDPQ had an option to invest $349 million in IPALCO through 2016 in exchange for a 17.65% equity stake. In March 2016, CDPQ exercised the remaining option by investing $134 million in IPALCO, which resulted in CDPQ's combined direct and indirect interest in IPALCO of 30%. The Company recognized an increase to additional paid-in-capital and a reduction to retained earnings of $84 million for the excess of the fair value of the shares over their book value. In June 2016, CDPQ contributed an additional $24 million to IPALCO, with no impact to the ownership structure of the investment. Any subsequent adjustments to allocate earnings and dividends to CDPQ will be classified as NCI within permanent equity as it is not probable that the shares will become redeemable.

18. REVENUE

The following table presents our revenue from contracts with customers and other revenue for the year ended December 31, 2018 (in millions):

	Year Ended December 31, 2018					
	US and Utilities SBU	South America SBU	MCAC SBU	Eurasia SBU	Corporate, Other and Eliminations	Total
Regulated Revenue						
Revenue from contracts with customers	$ 2,885	$ —	$ —	$ —	$ —	$ 2,885
Other regulated revenue	54	—	—	—	—	54
Total regulated revenue	$ 2,939	$ —	$ —	$ —	$ —	$ 2,939
Non-Regulated Revenue						
Revenue from contracts with customers	$ 972	$ 3,529	$ 1,642	$ 943	$ (11)	$ 7,075
Other non-regulated revenue [1]	319	4	86	312	1	722
Total non-regulated revenue	$ 1,291	$ 3,533	$ 1,728	$ 1,255	$ (10)	$ 7,797
Total revenue	$ 4,230	$ 3,533	$ 1,728	$ 1,255	$ (10)	$ 10,736

(1) Other non-regulated revenue primarily includes lease and derivative revenue not accounted for under ASC 606.

Contract Balances — The timing of revenue recognition, billings, and cash collections results in accounts receivable and contract liabilities. Accounts receivable represent unconditional rights to consideration and consist of both billed amounts and unbilled amounts typically resulting from sales under long-term contracts when revenue recognized exceeds the amount billed to the customer. We bill both generation and utilities customers on a contractually agreed-upon schedule, typically at periodic intervals (e.g., monthly). The calculation of revenue earned but not yet billed is based on the number of days not billed in the month, the estimated amount of energy delivered during those days and the estimated average price per customer class for that month.

Our contract liabilities consist of deferred revenue which is classified as current or noncurrent based on the timing of when we expect to recognize revenue. The current portion of our contract liabilities is reported in *Accrued and other liabilities* and the noncurrent portion is reported in *Other noncurrent liabilities* on the Consolidated Balance Sheets. The contract liabilities from contracts with customers were $109 million and $131 million as of December 31, 2018 and January 1, 2018, respectively.

Of the $131 million of contract liabilities reported at January 1, 2018, $36 million was recognized as revenue during the period ended December 31, 2018.

A significant financing arrangement exists for our Mong Duong plant in Vietnam. The plant was constructed under a build, operate, and transfer contract and will be transferred to the Vietnamese government after the completion of a 25 year PPA. The performance obligation to construct the facility was substantially completed in 2015. Approximately $1.4 billion of contract consideration related to the construction, but not yet collected through the 25 year PPA, was reflected as a loan receivable as of December 31, 2018.

Remaining Performance Obligations — The transaction price allocated to remaining performance obligations represents future consideration for unsatisfied (or partially unsatisfied) performance obligations at the end of the reporting period. As of December 31, 2018, the aggregate amount of transaction price allocated to remaining performance obligations was $15 million, primarily consisting of fixed consideration for the sale of renewable energy credits (RECs) in long-term contracts in the U.S. We expect to recognize revenue on approximately one-fifth of the remaining performance obligations in 2019, with the remainder recognized thereafter. The Company has elected to apply the optional disclosure exemptions under ASC 606. Therefore, the amount above excludes contracts with an original length of one year or less, contracts for which we recognize revenue based on the amount we have the right to invoice for services performed, and variable consideration allocated entirely to a wholly unsatisfied performance obligation when the consideration relates specifically to our efforts to satisfy the performance obligation and depicts the amount to which we expect to be entitled. As such, consideration for energy is excluded from the amounts above as the variable consideration relates to the amount of energy delivered and reflects the value the Company expects to receive for the energy transferred. Estimates of revenue expected to be recognized in future periods also exclude unexercised customer options to purchase additional goods or services that do not represent material rights to the customer.

19. OTHER INCOME AND EXPENSE

Other Income — Other income generally includes gains on asset sales and liability extinguishments, favorable judgments on contingencies, gains on contract terminations, allowance for funds used during construction and other income from miscellaneous transactions. The components are summarized as follows (in millions):

Year Ended December 31,	2018	2017	2016
Gain on remeasurement of contingent consideration [1]	$ 32	$ —	$ —
Allowance for funds used during construction (US Utilities)	8	26	29
Gain on sale of assets	4	1	4
Legal settlements [2]	—	60	—
Other	28	33	31
Total other income	$ 72	$ 120	$ 64

(1) Related to the amendment of the Oahu purchase agreement. See Note 24 —*Acquisitions* for further information.
(2) In December 2016, the Company and YPF entered into a settlement in which all parties agreed to give up any and all legal action related to gas supply contracts that were terminated in 2008 and have been in dispute since 2009. In January 2017, the YPF board approved the agreement and paid the Company $60 million, thereby resolving all uncertainties around the dispute.

Other Expense — Other expense generally includes losses on asset sales and dispositions, losses on legal contingencies, and losses from other miscellaneous transactions. The components are summarized as follows (in millions):

Year Ended December 31,	2018	2017	2016
Loss on sale and disposal of assets [1]	$ 30	$ 28	$ 12
Non-service pension and other postretirement costs	10	1	3
Allowance for other receivables [2]	7	—	52
Water rights write-off	—	19	6
Other	11	10	7
Total other expense	$ 58	$ 58	$ 80

(1) In September 2018, the Company recorded a $20 million loss due to damage associated with a lightning incident at the Andres facility in the Dominican Republic.
(2) During the fourth quarter of 2016, we recognized a full allowance on a non-trade receivable in the MCAC SBU as a result of payment delays and discussions with the counterparty. The allowance was related to certain reimbursements the Company was expecting in connection with a legal matter.

20. ASSET IMPAIRMENT EXPENSE

Year ended December 31, (in millions)	2018	2017	2016
Shady Point	$ 157	$ —	$ —
Nejapa	37	—	—
DPL	—	175	859
Laurel Mountain	—	121	—
Kazakhstan Hydroelectric	—	92	—
Kazakhstan CHPs	—	94	—
Kilroot	—	37	—
Buffalo Gap II	—	—	159
Buffalo Gap I	—	—	77
Other	14	18	1
Total	$ 208	$ 537	$ 1,096

Shady Point — In December 2018, the Company entered into an agreement to sell Shady Point, a coal-fired generation facility in the U.S. Due first to the uncertainty around future cash flows, and then upon meeting the held-for-sale criteria, the Company performed an impairment analysis of the Shady Point asset group in the second, third and fourth quarter of 2018, resulting in the recognition of total asset impairment expense of $157 million for the year ended December 31, 2018. Using the market approach, the asset group was determined to have a fair value of $30 million as of December 31, 2018. The sale is subject to regulatory approval and is expected to close during the second half of 2019. See Note 23—*Held-for-Sale and Dispositions* for further information. Shady Point is reported in the US and Utilities SBU reportable segment.

Nejapa — During the fourth quarter of 2018, the Company tested the recoverability of its long-lived assets at Nejapa, a landfill gas plant in El Salvador. Decreased production as a result of the landfill owner´s failure to perform improvements necessary to continue extracting gas from the landfill was identified as an impairment indicator. The Company determined that the carrying amount was not recoverable. The asset group, consisting of property, plant, and equipment and intangible assets, was determined to have a fair value of $5 million using the income approach. As a result, the Company recognized an asset impairment expense of $37 million as of December 31, 2018. Nejapa is reported in the US and Utilities SBU reportable segment.

DPL — In March 2017, the Board of Directors of DPL approved the retirement of the DPL operated and co-owned Stuart coal-fired and diesel-fired generating units, and the Killen coal-fired generating unit and combustion turbine on or before June 1, 2018. The Company performed an impairment analysis and determined that the carrying amounts of the facilities were not recoverable. The Stuart and Killen asset groups were determined to have fair values of $3 million and $8 million, respectively, using the income approach. As a result, the Company recognized total asset impairment expense of $66 million. The Stuart and Killen units were retired in May 2018. Prior to their retirement, Stuart and Killen were reported in the US and Utilities SBU reportable segment.

In December 2017, DPL entered into an agreement for the sale of six of its combustion turbine and diesel-fired generation facilities and related assets ("DPL peaker assets"). Upon meeting the held-for-sale criteria, the Company performed an impairment analysis and determined that the carrying value of the asset group of $346 million was greater than its fair value less costs to sell of $237 million. As a result, the Company recognized asset impairment expense of $109 million. DPL completed the sale of the peaker assets in March 2018. Prior to their sale, the DPL peaker assets were reported in the US and Utilities SBU reportable segment. See Note 23—*Held-for-Sale and Dispositions* for further information.

During the second quarter of 2016, the Company tested the recoverability of its long-lived generation assets at DPL. Uncertainty created by the Supreme Court of Ohio’s June 20, 2016 opinion regarding ESP 2, lower expectations of future revenue resulting from the most recent PJM capacity auction and higher anticipated environmental compliance costs resulting from third party studies were collectively determined to be an impairment indicator for these assets. The Company performed an impairment analysis and determined that the carrying amount of Killen, a coal-fired generation facility, and certain DPL peaking generation facilities were not recoverable. The Killen and DPL peaking generation asset groups were determined to have a fair value of $84 million and $5 million, respectively, using the income approach. As a result, the Company recognized total asset impairment expense of $235 million. DPL is reported in the US and Utilities SBU reportable segment.

During the fourth quarter of 2016, the Company tested the recoverability of its long-lived coal-fired generation assets and one gas-fired peaking plant at DPL. Uncertainty around the useful life of Stuart and Killen related to the Company’s ESP proceedings and lower forward dark spreads and capacity prices were collectively determined to be an impairment indicator for these assets. Market information indicating a significant decrease in the fair value of Zimmer and Miami Fort was determined to be an indicator of impairment for these assets. The lower forward dark spreads and capacity prices, along with the indicators at the other coal-fired facilities, collectively, resulted in an indicator of impairment for the Conesville asset group. For the gas-fired peaking plant, significant incremental capital expenditures relative to its fair value, and an impairment charge taken at this facility in the second quarter of 2016, were collectively determined to be impairment indicators for this asset. The Company performed an impairment analysis for each of these asset groups and determined that their carrying amounts were not recoverable. The Stuart, Killen, Miami Fort, Zimmer, Conesville and the gas-fired peaking plant asset groups were determined to have fair values of $57 million, $43 million, $36 million, $24 million, $1 million and $2 million, respectively, using the market approach for Miami Fort and Zimmer and the income approach for the remaining asset groups. As a result, the Company recognized total asset impairment expense of $624 million. DPL is reported in the US and Utilities SBU reportable segment.

Laurel Mountain — During the fourth quarter of 2017, the Company tested the recoverability of its long-lived assets at Laurel Mountain, a wind farm in the U.S. Impairment indicators were identified based on a decline in forward pricing. The Company determined that the carrying amount was not recoverable. The Laurel Mountain asset group was determined to have a fair value of $33 million using the income approach. As a result, the Company recognized an asset impairment expense of $121 million. Laurel Mountain is reported in the US and Utilities SBU reportable segment.

Kilroot — During the fourth quarter of 2017, the Company tested the recoverability of its long-lived assets at Kilroot, a coal and oil-fired plant in Northern Ireland, as Kilroot was not successful in bidding its coal units into the December 2017 capacity auction for the newly implemented I-SEM market. The Company determined that the carrying amount of the asset group was not recoverable. The Kilroot asset group was determined to have a fair value of $20 million using the income approach. As a result, the Company recognized an asset impairment expense of $37 million, which was limited to the carrying value of the coal units. Kilroot is reported in the Eurasia SBU reportable segment.

Kazakhstan Hydroelectric — In April 2017, the Republic of Kazakhstan stated the concession agreements would not be extended for Shulbinsk HPP and Ust-Kamenogorsk HPP, two hydroelectric plants in Kazakhstan, and initiated the process to transfer these plants back to the government. Upon meeting the held-for-sale criteria in the second quarter of 2017, the Company performed an impairment analysis and determined the carrying value of the asset group of $190 million, which included cumulative translation losses of $100 million, was greater than its fair value less costs to sell of $92 million. As a result, the Company recognized asset impairment expense of $92 million limited to the carrying value of the long-lived assets. The Company completed the transfer of the plants in October 2017. Prior to their transfer, the Kazakhstan hydroelectric plants were reported in the Eurasia SBU reportable segment. See Note 23—*Held-for-Sale and Dispositions* for further information.

Kazakhstan CHPs — In January 2017, the Company entered into an agreement for the sale of Ust-Kamenogorsk CHP and Sogrinsk CHP, its combined heating and power coal plants in Kazakhstan. Upon meeting the held-for-sale criteria in the first quarter of 2017, the Company performed an impairment analysis and determined that the carrying value of the asset group of $171 million, which included cumulative translation losses of $92 million, was greater than its fair value less costs to sell of $29 million. As a result, the Company recognized asset impairment expense of $94 million limited to the carrying value of the long-lived assets. The Company completed the sale of its interest in the Kazakhstan CHP plants in April 2017. Prior to their sale, the plants were reported in the Eurasia SBU reportable segment. See Note 23—*Held-for-Sale and Dispositions* for further information.

Buffalo Gap I — During 2016, the Company tested the recoverability of its long-lived assets at Buffalo Gap I. Low wind production during 2016 resulted in management lowering future expectations of production and therefore future forecasted revenues. As such this was determined to be an impairment indicator. The Company determined that the carrying amount of the asset group was not recoverable. The Buffalo Gap I asset group was determined to have a fair value of $36 million using the income approach. As a result, the Company recognized asset impairment expense of $77 million ($23 million attributable to AES). Buffalo Gap I is reported in the US and Utilities SBU reportable segment.

Buffalo Gap II — During 2016, the Company tested the recoverability of its long-lived assets at Buffalo Gap II. Impairment indicators were identified based on a decline in forward power curves. The Company determined that the carrying amount was not recoverable. The Buffalo Gap II asset group was determined to have a fair value of $92 million using the income approach. As a result, the Company recognized asset impairment expense of $159 million ($49 million attributable to AES). Buffalo Gap II is reported in the US and Utilities SBU reportable segment.

21. INCOME TAXES

U.S. Tax Reform — In 2017, the U.S. enacted the Tax Cuts and Jobs Act (the “TCJA”). The TCJA significantly changed U.S. corporate income tax law. Among other changes effective in 2017, the TCJA required companies to pay a one-time tax on certain unrepatriated earnings of foreign subsidiaries. Many other changes took effect in 2018, including a limit on the deductibility of interest expense and a new regime for taxing certain earnings of foreign subsidiaries.

The Company recognized the income tax effects of the TCJA in accordance with Staff Accounting Bulletin No. 118 (“SAB 118”) which provides SEC guidance on the application of ASC 740, *Income Taxes*, in the reporting period in which the TCJA was signed into law. Accordingly, the Company’s 2017 financial statements reflected provisional amounts for those impacts for which the accounting under ASC 740 was incomplete, but a reasonable estimate could be determined. As of December 31, 2018, the Company's accounting for the initial impacts of the TCJA are complete under SAB 118.

For the year ended December 31, 2018 the Company increased its estimate of the one-time transition tax by $194 million to $869 million. The estimated tax expense recognized for the year ended December 31, 2017 relating to the remeasurement of deferred tax assets and liabilities from an income tax rate of 35% to 21%, decreased $77 million, resulting in a total remeasurement benefit of $38 million.

Argentine Tax Reform — In December 2017, the Argentine government enacted reforms to its income tax laws that resulted in a decrease to statutory income tax rates for our Argentine businesses from 35% to 30% in 2018-2019 and to 25% for 2020 and future years. The impact of remeasuring deferred taxes to account for the enacted change in future applicable income tax rates was recognized as income tax benefit in the fourth quarter of 2017, resulting in a decrease of $21 million to consolidated income tax expense.

Chilean Tax Reform — In February 2016, the Chilean government enacted further reforms to its income tax laws that resulted in an increase to statutory income tax rates for most of our Chilean businesses from 25% to 25.5% in 2017 and to 27% for 2018 and future years. The impact of remeasuring deferred taxes to account for the enacted change in future applicable income tax rates was recognized as a discrete income tax expense in the first quarter of 2016, resulting in an increase of $26 million to consolidated income tax expense.

Income Tax Provision — The following table summarizes the expense for income taxes on continuing operations for the periods indicated (in millions):

December 31,		2018	2017	2016
Federal:	Current	$ 7	$ —	$ 2
	Deferred	186	545	(361)
State:	Current	2	—	1
	Deferred	5	1	(4)
Foreign:	Current	378	335	318
	Deferred	130	109	76
Total		$ 708	$ 990	$ 32

Effective and Statutory Rate Reconciliation — The following table summarizes a reconciliation of the U.S. statutory federal income tax rate to the Company's effective tax rate as a percentage of income from continuing operations before taxes for the periods indicated:

December 31,	2018	2017	2016
Statutory Federal tax rate	21 %	35 %	35 %
State taxes, net of Federal tax benefit	2 %	(7)%	(18)%
Taxes on foreign earnings	9 %	— %	(46)%
Valuation allowance	(2)%	10 %	10 %
Uncertain tax positions	— %	— %	4 %
Noncontrolling Interest on Buffalo Gap impairments	— %	— %	31 %
Change in tax law	6 %	90 %	12 %
Other—net	(1)%	— %	(11)%
Effective tax rate	35 %	128 %	17 %

For 2018, the 6% change in tax law item relates primarily to changes in estimate under SAB 118 of the impacts of adoption of the TCJA. The Company recognized tax expense of $194 million related to revised estimates of the one-time transition tax in accordance with proposed regulations issued by the U.S. Treasury in 2018. The adjustment was due in large part to the approach the proposed regulations adopted to determine the fair value of our interests in publicly traded subsidiaries. The Company also recognized tax benefit of $77 million related to revised estimates of deferred tax remeasurement. Included in the 9% taxes on foreign earnings item is $124 million of U.S. GILTI tax expense related to foreign subsidiaries, including the sale of our interest in Masinloc.

For 2017, the 90% change in tax law item relates primarily to the impact of U.S. and Argentina tax reform. The impact of the U.S one-time transition tax and remeasurement of deferred taxes represents 88% and 5%, respectively, which is partially offset by the tax benefit resulting from Argentina tax reform representing 3%.

For 2016, the 31% Buffalo Gap impairments item relates to the amounts of impairment allocated to noncontrolling interest which is nondeductible.

Income Tax Receivables and Payables — The current income taxes receivable and payable are included in *Other Current Assets* and *Accrued and Other Liabilities*, respectively, on the accompanying Consolidated Balance Sheets. The noncurrent income taxes receivable and payable are included in Other Noncurrent Assets and Other Noncurrent Liabilities, respectively, on the accompanying Consolidated Balance Sheets. The following table summarizes the income taxes receivable and payable as of the periods indicated (in millions):

December 31,	2018	2017
Income taxes receivable—current	$ 163	$ 147
Income taxes receivable—noncurrent	8	—
Total income taxes receivable	$ 171	$ 147
Income taxes payable—current	$ 210	$ 129
Income taxes payable—noncurrent	7	17
Total income taxes payable	$ 217	$ 146

Deferred Income Taxes — Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and (b) operating loss and tax credit carryforwards. These items are stated at the enacted tax rates that are expected to be in effect when taxes are actually paid or recovered.

As of December 31, 2018, the Company had federal net operating loss carryforwards for tax return purposes of approximately $1.1 billion expiring in years 2033 to 2036. The Company also had federal general business tax credit carryforwards of approximately $22 million expiring primarily from 2021 to 2038, and federal alternative minimum tax credits of approximately $15 million that may be fully recovered by 2021 under the TCJA. Additionally, the Company had state net operating loss carryforwards as of December 31, 2018 of approximately $8.5 billion expiring in years 2019 to 2038. As of December 31, 2018, the Company had foreign net operating loss carryforwards of approximately $2.4 billion that expire at various times beginning in 2019 and some of which carry forward without expiration, and tax credits available in foreign jurisdictions of approximately $14 million, $13 million of which expire in 2021 and $1 million of which expire in years 2024 to 2029.

Valuation allowances decreased $120 million during 2018 to $868 million at December 31, 2018. This net decrease was primarily the result of valuation allowance activity at certain of our Brazil subsidiaries and U.S. states.

Valuation allowances increased $112 million during 2017 to $988 million at December 31, 2017. This net increase was primarily the result of valuation allowance activity at certain of our Brazil subsidiaries.

The Company believes that it is more likely than not that the net deferred tax assets as shown below will be realized when future taxable income is generated through the reversal of existing taxable temporary differences and income that is expected to be generated by businesses that have long-term contracts or a history of generating taxable income.

The following table summarizes deferred tax assets and liabilities, as of the periods indicated (in millions):

December 31,	2018	2017
Differences between book and tax basis of property	$ (1,418)	$ (1,424)
Other taxable temporary differences	(243)	(143)
Total deferred tax liability	(1,661)	(1,567)
Operating loss carryforwards	1,066	1,439
Capital loss carryforwards	52	63
Bad debt and other book provisions	62	66
Tax credit carryforwards	55	51
Other deductible temporary differences	111	60
Total gross deferred tax asset	1,346	1,679
Less: valuation allowance	(868)	(988)
Total net deferred tax asset	478	691
Net deferred tax (liability)	$ (1,183)	$ (876)

The Company considers undistributed earnings of certain foreign subsidiaries to be indefinitely reinvested outside of the U.S. Except for the one-time transition tax in the U.S., no taxes have been recorded with respect to our indefinitely reinvested earnings in accordance with the relevant accounting guidance for income taxes. Should the earnings be remitted as dividends, the Company may be subject to additional foreign withholding and state income taxes. Under the TCJA, future distributions from foreign subsidiaries will generally be subject to a federal dividends received deduction in the U.S. As of December 31, 2018, the cumulative amount of U.S. GAAP foreign un-remitted earnings upon which additional income taxes have not been provided is approximately $4 billion. It is not practicable to estimate the amount of any additional taxes which may be payable on the undistributed earnings.

Income from operations in certain countries is subject to reduced tax rates as a result of satisfying specific commitments regarding employment and capital investment. The Company's income tax benefits related to the tax status of these operations are estimated to be $35 million, $26 million and $20 million for the years ended December 31, 2018, 2017 and 2016, respectively. The per share effect of these benefits after noncontrolling interests was $0.04, $0.03 and $0.02 for the years ended December 31, 2018, 2017 and 2016, respectively. Included in the Company's income tax benefits is the benefit related to our operations in Vietnam, which is estimated to be $19 million, $13 million and $15 million for the years ended December 31, 2018, 2017 and 2016, respectively. The per share effect of these benefits related to our operations in Vietnam after noncontrolling interest was $0.01, $0.01 and $0.01 for the years ended December 31, 2018, 2017 and 2016, respectively.

The following table shows the income (loss) from continuing operations, before income taxes, net equity in earnings of affiliates and noncontrolling interests, for the periods indicated (in millions):

December 31,	2018	2017	2016
U.S.	$ (218)	$ (511)	$ (1,305)
Non-U.S.	2,236	1,282	1,492
Total	$ 2,018	$ 771	$ 187

Uncertain Tax Positions — Uncertain tax positions have been classified as noncurrent income tax liabilities unless they are expected to be paid within one year. The Company's policy for interest and penalties related to income tax exposures is to recognize interest and penalties as a component of the provision for income taxes in the Consolidated Statements of Operations. The following table shows the total amount of gross accrued income taxes related to interest and penalties included in the Consolidated Balance Sheets for the periods indicated (in millions):

December 31,	2018	2017
Interest related	$ 4	$ 7
Penalties related	—	—

The following table shows the expense/(benefit) related to interest and penalties on unrecognized tax benefits for the periods indicated (in millions):

December 31,	2018	2017	2016
Total expense (benefit) for interest related to unrecognized tax benefits	$ (3)	$ 1	$ 2
Total expense for penalties related to unrecognized tax benefits	—	—	—

We are potentially subject to income tax audits in numerous jurisdictions in the U.S. and internationally until the applicable statute of limitations expires. Tax audits by their nature are often complex and can require several years to complete. The following is a summary of tax years potentially subject to examination in the significant tax and business jurisdictions in which we operate:

Jurisdiction	Tax Years Subject to Examination
Argentina	2012-2018
Brazil	2013-2018
Chile	2015-2018
Colombia	2016-2018
Dominican Republic	2016-2018
El Salvador	2016-2018
Netherlands	2014-2018
Panama	2015-2018
United Kingdom	2012-2018
United States (Federal)	2015-2018

As of December 31, 2018, 2017 and 2016, the total amount of unrecognized tax benefits was $463 million, $348 million and $352 million, respectively. The total amount of unrecognized tax benefits that would benefit the effective tax rate as of December 31, 2018, 2017 and 2016 is $446 million, $332 million and $332 million, respectively, of which $33 million, $29 million and $24 million, respectively, would be in the form of tax attributes that would warrant a full valuation allowance. Further, the total amount of unrecognized tax benefit that would benefit the effective tax rate as of 2018 would be reduced by approximately $161 million of tax expense related to remeasurement from 35% to 21%.

The total amount of unrecognized tax benefits anticipated to result in a net decrease to unrecognized tax benefits within 12 months of December 31, 2018 is estimated to be between $0 million and $10 million, primarily relating to statute of limitation lapses and tax exam settlements.

The following is a reconciliation of the beginning and ending amounts of unrecognized tax benefits for the periods indicated (in millions):

	2018	2017	2016
Balance at January 1	$ 348	$ 352	$ 364
Additions for current year tax positions	2	—	2
Additions for tax positions of prior years	146	2	1
Reductions for tax positions of prior years	(26)	(5)	(1)
Settlements	—	—	(13)
Lapse of statute of limitations	(7)	(1)	(1)
Balance at December 31	$ 463	$ 348	$ 352

The Company and certain of its subsidiaries are currently under examination by the relevant taxing authorities for various tax years. The Company regularly assesses the potential outcome of these examinations in each of the taxing jurisdictions when determining the adequacy of the amount of unrecognized tax benefit recorded. While it is often difficult to predict the final outcome or the timing of resolution of any particular uncertain tax position, we believe we have appropriately accrued for our uncertain tax benefits. However, audit outcomes and the timing of audit settlements and future events that would impact our previously recorded unrecognized tax benefits and the range of anticipated increases or decreases in unrecognized tax benefits are subject to significant uncertainty. It is possible that the ultimate outcome of current or future examinations may exceed our provision for current unrecognized tax benefits in amounts that could be material, but cannot be estimated as of December 31, 2018. Our effective tax rate and net income in any given future period could therefore be materially impacted.

22. DISCONTINUED OPERATIONS

Due to a portfolio evaluation in the first half of 2016, management decided to pursue a strategic shift of its distribution companies in Brazil, Sul and Eletropaulo, to reduce the Company's exposure to the Brazilian distribution market. The disposals of Sul and Eletropaulo were completed in October 2016 and June 2018, respectively.

Eletropaulo — In November 2017, Eletropaulo converted its preferred shares into ordinary shares and transitioned the listing of those shares to the Novo Mercado, which is a listing segment of the Brazilian stock exchange with the highest standards of corporate governance. Upon conversion of the preferred shares into ordinary shares, AES no longer controlled Eletropaulo, but maintained significant influence over the business. As a result, the Company deconsolidated Eletropaulo. After deconsolidation, the Company's 17% ownership interest was reflected as an equity method investment. The Company recorded an after-tax loss on deconsolidation of $611 million, which primarily consisted of $455 million related to cumulative translation losses and $243 million related to pension losses reclassified from AOCL.

In December 2017, all the remaining criteria were met for Eletropaulo to qualify as a discontinued operation. Therefore, its results of operations and financial position were reported as such in the consolidated financial statements for all periods presented.

In June 2018, the Company completed the sale of its entire 17% ownership interest in Eletropaulo through a bidding process hosted by the Brazilian securities regulator, CVM. Gross proceeds of $340 million were received at our subsidiary in Brazil, subject to the payment of taxes. Upon disposal of Eletropaulo, the Company recorded a pre-tax gain on sale of $243 million (after-tax $199 million).

Excluding the gain on sale, Eletropaulo's pre-tax loss attributable to AES was immaterial for the year ended December 31, 2018. Eletropaulo's pre-tax loss attributable to AES, including the loss on deconsolidation, for the years ended December 31, 2017 and 2016 was $633 million and $192 million, respectively. Prior to its classification as discontinued operations, Eletropaulo was reported in the South America SBU reportable segment.

Sul — The Company executed an agreement for the sale of Sul, a wholly-owned subsidiary, in June 2016. The results of operations and financial position of Sul are reported as discontinued operations in the consolidated financial statements for all periods presented. Upon meeting the held-for-sale criteria, the Company recognized an after-tax loss of $382 million comprised of a pre-tax impairment charge of $783 million, offset by a tax benefit of $266 million related to the impairment of the Sul long lived assets and a tax benefit of $135 million for deferred taxes related to the investment in Sul. Prior to the impairment charge, the carrying value of the Sul asset group of $1.6 billion was greater than its approximate fair value less costs to sell. However, the impairment charge was limited to the carrying value of the long lived assets of the Sul disposal group.

On October 31, 2016, the Company completed the sale of Sul and received final proceeds less costs to sell of $484 million, excluding contingent consideration. Upon disposal of Sul, the Company incurred an additional after-tax loss on sale of $737 million. The cumulative impact to earnings of the impairment and loss on sale was $1.1 billion. This includes the reclassification of approximately $1 billion of cumulative translation losses resulting in a net reduction to the Company's stockholders' equity of $92 million.

Sul's pre-tax loss attributable to AES for the year ended December 31, 2016 was $1.4 billion. Prior to its classification as discontinued operations, Sul was reported in the South America SBU reportable segment.

Borsod — In 2011, Borsod, which held two coal and biomass-fired generation plants in Hungary, filed for liquidation and was deconsolidated with its historical operating results reflected in discontinued operations under prior accounting guidance. In October 2018, the liquidation was completed and the Company recognized a deferred gain of $26 million, primarily comprised of a $20 million write-off of cumulative translation balances. Prior to its liquidation, Borsod was reported in the Eurasia SBU reportable segment.

The following table summarizes the carrying amounts of the major classes of assets and liabilities of discontinued operations at December 31, 2017:

(in millions)	December 31, 2017
Assets of discontinued operations and held-for-sale businesses:	
Investments in and advances to affiliates [1]	$ 86
Total assets of discontinued operations	86
Other assets of businesses classified as held-for-sale [2]	1,948
Total assets of discontinued operations and held-for-sale businesses	$ 2,034
Liabilities of discontinued operations and held-for-sale businesses:	
Other liabilities of businesses classified as held-for-sale [2]	1,033
Total liabilities of discontinued operations and held-for-sale businesses	$ 1,033

(1) Represents the Company's 17% ownership interest in Eletropaulo.
(2) Masinloc, Eletrica Santiago, and the DPL peaker assets were classified as held-for-sale as of December 31, 2017. See Note 23—*Held-for-Sale and Dispositions* for further information.

Excluding the gain on sale of Eletropaulo and deferred gain on liquidation of Borsod, income from discontinued operations and cash flows from operating and investing activities of discontinued operations were immaterial for the year ended December 31, 2018.

The following table summarizes the major line items constituting *losses from discontinued operations* for the periods indicated (in millions):

December 31,	2017	2016
Income (loss) from discontinued operations, net of tax:		
Revenue — regulated	$ 3,320	$ 4,036
Cost of sales	(3,151)	(3,954)
Other income and expense items that are not major [1]	(166)	(160)
Income (loss) from operations of discontinued businesses	3	(78)
Loss from disposal and impairments of discontinued businesses	(611)	(1,385)
Income (loss) from discontinued operations	(608)	(1,463)
Less: Net income attributable to noncontrolling interests	(25)	(142)
Income (loss) from discontinued operations attributable to The AES Corporation	(633)	(1,605)
Income tax benefit (expense)	(21)	495
Loss from discontinued operations, net of tax	$ (654)	$ (1,110)

(1) Includes a loss contingency recognized by our equity method investment in discontinued operations.

The following table summarizes the operating and investing cash flows from discontinued operations for the periods indicated (in millions):

December 31,	2017	2016
Cash flows provided by operating activities of discontinued operations	$ 164	$ 529
Cash flows used in investing activities of discontinued operations	(288)	(368)

23. HELD-FOR-SALE AND DISPOSITIONS

Held-for-Sale

Shady Point — In December 2018, the Company entered into an agreement to sell Shady Point, a U.S. coal-fired generating facility, for $30 million, subject to customary purchase price adjustments. The sale is subject to regulatory approval and is expected to close during the second half of 2019. As of December 31, 2018, Shady Point was classified as held-for-sale, but did not meet the criteria to be reported as discontinued operations. Shady Point's carrying value as of December 31, 2018 was $30 million. Excluding impairment charges, pre-tax income attributable to AES was $19 million in each of the years ended December 31, 2018, 2017 and 2016. Shady Point is reported in the US and Utilities SBU reportable segment. See Note 20—*Asset Impairment Expense* for further information.

Redondo Beach — In October 2018, the Company entered into an agreement to sell land held by AES Redondo Beach, a gas-fired generating facility in California. The sale is expected to close during the first half of 2019. As of December 31, 2018, the $24 million carrying value of the land held by Redondo Beach was classified as held-for-sale. Redondo Beach is reported in the US and Utilities SBU reportable segment.

Dispositions

CTNG — In December 2018, AES Gener completed the sale of CTNG, an entity that holds transmission lines in Chile, for $225 million, subject to customary post-closing adjustments, resulting in a pre-tax gain on sale of $129 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, CTNG was reported in the South America SBU reportable segment.

Electrica Santiago — In May 2018, AES Gener completed the sale of Electrica Santiago for total consideration of $287 million, resulting in a pre-tax gain on sale of $69 million after post-closing adjustments. Electrica Santiago consisted of four gas and diesel-fired generation plants in Chile. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, Electrica Santiago was reported in the South America SBU reportable segment.

Stuart and Killen — In May 2018, DPL retired the co-owned Stuart coal-fired and diesel-fired generating units, and the Killen coal-fired generating unit and combustion turbine. Prior to their retirement, Stuart and Killen were reported in the US and Utilities SBU reportable segment. See Note 20—*Asset Impairment Expense* for further information.

Masinloc — In March 2018, the Company completed the sale of its entire 51% equity interest in Masinloc for cash proceeds of $1.05 billion, resulting in a pre-tax gain on sale of $772 million after post-closing adjustments, subject to U.S. income tax. Masinloc consisted of a coal-fired generation plant in operation, a coal-fired generation plant under construction and an energy storage facility all located in the Philippines. The sale did not meet the criteria to be reported as discontinued operations. Prior to its sale, Masinloc was reported in the Eurasia SBU reportable segment.

In 2014, the Company completed the sale of 45% of its ownership interest in Masinloc for $436 million, including $23 million of consideration that was contingent upon the achievement of certain tax restructuring efficiencies. In December 2017, the related contingency expired and the $23 million of contingent consideration was recognized as a gain in *Gain (loss) on disposal and sale of business interests* in the Consolidated Statement of Operations.

DPL peaker assets — In March 2018, DPL completed the sale of six of its combustion turbine and diesel-fired generation facilities and related assets ("DPL peaker assets") for total proceeds of $239 million, inclusive of estimated working capital and subject to customary post-closing adjustments, resulting in a loss on sale of $2 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to their sale, the DPL peaker assets were reported in the US and Utilities SBU reportable segment.

Beckjord facility — In February 2018, DPL transferred its interest in Beckjord, a coal-fired generation facility retired in 2014, including its obligations to remediate the facility and its site. The transfer resulted in cash expenditures of $15 million, inclusive of disposal charges, and a loss on disposal of $12 million. Prior to the transfer, Beckjord was reported in the US and Utilities SBU reportable segment.

Advancion Energy Storage — In January 2018, the Company deconsolidated the AES Advancion energy storage development business and contributed it to the Fluence joint venture, resulting in a gain on sale of $23 million. See Note 7—*Investments in and Advances to Affiliates* for further discussion. Prior to the transfer, the AES Advancion energy storage development business was reported as part of Corporate and Other.

Zimmer and Miami Fort — In December 2017, DPL and AES Ohio Generation completed the sale of Zimmer and Miami Fort, two coal-fired generating plants, for net proceeds of $70 million, resulting in a gain on sale of $13 million. The sale did not meet the criteria to be reported as discontinued operations. Prior to their sale, Zimmer and Miami Fort were reported in the US and Utilities SBU reportable segment.

Kazakhstan Hydroelectric — Affiliates of the Company (the "Affiliates") previously operated Shulbinsk HPP and Ust-Kamenogorsk HPP (the "HPPs"), two hydroelectric plants in Kazakhstan, under a concession agreement with the Republic of Kazakhstan ("RoK"). In April 2017, the RoK initiated the process to transfer these plants back to the RoK. The RoK indicated that arbitration would be necessary to determine the correct Return Share Transfer Payment ("RST") and, rather than paying the Affiliates, deposited the RST into an escrow account. In exchange, the Affiliates transferred 100% of the shares in the HPPs to the RoK, under protest and with a full reservation of rights. The Company recorded a loss on disposal of $33 million in the fourth quarter of 2017. In February 2018, the Affiliates initiated the arbitration process in international court to recover at least $75 million of the RST placed in escrow, based on the September 30, 2017 RST calculation. As of December 31, 2018, the arbitration proceedings are ongoing, and additional losses are not considered probable at this time. However, additional losses may be incurred if some or all of the disputed consideration is not paid by the RoK via a mutually acceptable settlement, or upon any unfavorable decision rendered by the arbiter. The transfer did not meet the criteria to be reported as discontinued operations. Prior to their transfer, the Kazakhstan HPPs were reported in the Eurasia SBU reportable segment. See Note 20—*Asset Impairment Expense* for further information.

Kazakhstan CHPs — In April 2017, the Company completed the sale of Ust-Kamenogorsk CHP and Sogrinsk CHP, its combined heating and power coal plants in Kazakhstan, for net proceeds of $24 million. The Company recognized a pre-tax loss on sale of $49 million, primarily related to cumulative translation losses. The sale did not meet the criteria to be reported as discontinued operations. Prior to their sale, the Kazakhstan CHP plants were reported in the Eurasia SBU reportable segment. See Note 20—*Asset Impairment Expense* for further information.

UK Wind — During 2016, the Company determined it no longer had control of its wind development projects in the United Kingdom ("UK Wind") as the Company no longer held seats on the board of directors. In accordance with accounting guidance, UK Wind was deconsolidated and a loss on deconsolidation of $20 million was recorded to *Gain (loss) on disposal and sale of business interests* in the Consolidated Statement of Operations to write off the Company's noncontrolling interest in the project. The UK Wind projects were reported in the Eurasia SBU reportable segment.

DPLER — In January 2016, the Company completed the sale of DPLER, a competitive retail marketer selling electricity to customers in Ohio, and recognized a gain on sale of $49 million. Proceeds of $76 million were received in December 2015. DPLER did not meet the criteria to be reported as a discontinued operation. DPLER's results were therefore reflected within continuing operations in the Consolidated Statements of Operations. Prior to its sale, DPLER was reported in the US and Utilities SBU reportable segment.

Kelanitissa — In January 2016, the Company completed the sale of its interest in Kelanitissa, a diesel-fired generation plant in Sri Lanka, for $18 million, resulting in a loss on sale of $5 million. The sale did not meet the criteria to be reported as discontinued operations. Kelanitissa's results were therefore reflected within continuing operations in the Consolidated Statements of Operations. Prior to its sale, Kelanitissa was reported in the Eurasia SBU reportable segment.

Jordan — In February 2016, the Company completed the sale of 40% of its interest in a wholly-owned subsidiary in Jordan that owns a controlling interest in the Jordan IPP4 gas-fired plant for $21 million. The transaction was accounted for as a sale of in-substance real estate and a pre-tax gain of $4 million, net of transaction costs, was recognized in net income. The cash proceeds from the sale are reflected in *Proceeds from the sale of business interests, net of cash and restricted cash sold* on the Consolidated Statement of Cash Flows for the period ended December 31, 2016. After completion of the sale, the Company has a 36% economic interest in Jordan IPP4 and continues to manage and operate the plant. As the Company maintained control after the sale, Jordan IPP4 continues to be consolidated by the Company within the Eurasia SBU reportable segment.

Excluding any impairment charge or gain/loss on sale, pre-tax income (loss) attributable to AES of disposed businesses was as follows (in millions):

Year Ended December 31,	2018	2017	2016
Masinloc	$ 9	$ 103	$ 103
Stuart and Killen [1][2]	77	17	—
DPL peaker assets	7	17	20
Zimmer and Miami Fort	—	26	(14)
Kazakhstan Hydroelectric	—	33	34
Kazakhstan CHPs	—	13	12
Other	14	9	11
Total	$ 107	$ 218	$ 166

(1) The Company entered into contracts to buy back all open capacity years for Stuart and Killen at prices lower than the PJM capacity revenue prices. As such, the Company continues to earn capacity margin.

(2) Reductions in the asset retirement obligations for ash ponds and landfills at Stuart and Killen in 2018 resulted in a $32 million reduction to cost of sales. See Note 3—*Property, Plant and Equipment* for further information.

24. ACQUISITIONS

Distributed Energy — In December 2018, Distributed Energy acquired the outstanding noncontrolling interest in a partnership holding various solar projects from its tax equity partner for $23 million of consideration in a non-cash transaction through the assumption of debt, increasing the Company's ownership to 100%. The partnership was previously classified as an equity method investment. The transaction was accounted for as an asset acquisition, therefore the Company remeasured the equity investment at fair value and recognized a loss of $5 million in *Other expense* in the Consolidated Statement of Operations. The fair value of the investment, along with the consideration transferred, plus transaction costs, were allocated to the individual assets acquired and liabilities assumed based on their relative fair values. Distributed Energy is reported in the US and Utilities SBU reportable segment.

In September 2016, Distributed Energy acquired the equity interest of various projects held by multiple partnerships for approximately $43 million. These partnerships were previously classified as equity method investments. In accordance with the accounting guidance for business combinations, the Company recorded the opening balance sheets of the acquired businesses based on the purchase price allocation as of the acquisition date.

Oahu — In November 2018, AES Oahu amended a 2017 agreement to acquire 100% of Na Pua Makani Power Partners, a partnership designed to develop and hold a wind project in Hawaii. The fair value of the initial consideration was $53 million, of which $48 million was contingent on meeting predefined development milestones. The transaction was accounted for as an acquisition of a variable interest entity that did not meet the definition of a business, therefore the assets acquired and liabilities assumed were recorded at their fair values, which equaled the fair value of the consideration. As a result of the amendment, the Company paid $11 million in 2018 and the contingent consideration was reduced to $5 million, resulting in a $32 million gain on remeasurement of contingent consideration recorded in *Other income* in the Consolidated Statement of Operations. AES Oahu is reported in the US and Utilities SBU reportable segment.

Guaimbê Solar Complex — In September 2018, AES Tietê completed the acquisition of the Guaimbê Solar Complex ("Guaimbê") from Cobra do Brasil for $152 million, subject to post-closing adjustments, comprised of the exchange of $119 million of non-convertible debentures in project financing and additional cash consideration of $33 million. The transaction was accounted for as an asset acquisition, therefore the consideration transferred, plus transaction costs, were allocated to the individual assets acquired and liabilities assumed based on their relative fair values. Any differences arising from post-closing adjustments will be allocated accordingly. Guaimbê is reported in the South America SBU reportable segment.

Alto Sertão II — In August 2017, the Company completed the acquisition of the Alto Sertão II Wind Complex ("Alto Sertão II") from Renova Energia S.A. for $179 million, plus the assumption of $346 million of non-recourse debt. At closing, the Company made a cash payment of $143 million, which excluded holdbacks related to indemnifications. In September 2018, an additional $12 million was paid to settle a portion of the remaining indemnification liability. In the first quarter of 2018, the Company finalized the purchase price allocation related to the acquisition of Alto Sertão II. There were no significant adjustments made to the preliminary purchase price allocation recorded in the third quarter of 2017 when the acquisition was completed. The assets acquired and liabilities assumed at the acquisition date were recorded at fair value, including a contingent liability for earn-out payments of $18 million, based on the final purchase price allocation at March 31, 2018. Subsequent changes to the fair value of the earn-out payments will be reflected in earnings. Alto Sertão II is reported in the South America SBU reportable segment.

25. EARNINGS PER SHARE

Basic and diluted earnings per share are based on the weighted-average number of shares of common stock and potential common stock outstanding during the period. Potential common stock, for purposes of determining diluted earnings per share, includes the effects of dilutive RSUs, stock options and convertible securities. The effect of such potential common stock is computed using the treasury stock method or the if-converted method, as applicable.

The following table is a reconciliation of the numerator and denominator of the basic and diluted earnings per share computation for income from continuing operations for the years ended December 31, 2018, 2017 and 2016, where income represents the numerator and weighted-average shares represent the denominator.

Year Ended December 31,	2018			2017			2016		
(in millions, except per share data)	Income	Shares	$ per Share	Loss	Shares	$ per Share	Loss	Shares	$ per Share
BASIC EARNINGS (LOSS) PER SHARE									
Income (loss) from continuing operations attributable to The AES Corporation common stockholders [1]	$ 985	662	$ 1.49	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)
EFFECT OF DILUTIVE SECURITIES									
Restricted stock units	—	3	(0.01)	—	—	—	—	—	—
DILUTED EARNINGS (LOSS) PER SHARE	$ 985	665	$ 1.48	$ (507)	660	$ (0.77)	$ (25)	660	$ (0.04)

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(1) Loss from continuing operations, net of tax, of $20 million less the $5 million adjustment to retained earnings to record the DP&L redeemable preferred stock at its redemption value as of December 31, 2016.

The calculation of diluted earnings per share excluded stock awards and convertible debentures which would be anti-dilutive. The calculation of diluted earnings per share excluded 2 million, 7 million and 8 million stock awards outstanding for the years ended December 31, 2018, 2017 and 2016, respectively, that could potentially dilute basic earnings per share in the future. Additionally, for the year ended December 31, 2016, all 15 million convertible debentures were excluded from the earnings per share calculation. The Company redeemed all of its existing convertible debentures in June 2017.

For the years ended December 31, 2017 and 2016, respectively, the calculation of diluted earnings per share also excluded 4 million and 5 million outstanding restricted stock units that could potentially dilute earnings per share in the future because their impact would be anti-dilutive given the loss from continuing operations. Had the Company generated income, 2 million potential shares of common stock related to the restricted stock units would have been included in diluted average shares outstanding for each period.

26. RISKS AND UNCERTAINTIES

AES is a diversified power generation and utility company organized into four market-oriented SBUs. See additional discussion of the Company's principal markets in Note 15—*Segment and Geographic Information*. Within our four SBUs, we have two primary lines of business: generation and utilities. The generation line of business uses a wide range of fuels and technologies to generate electricity such as coal, gas, hydro, wind, solar and biomass. Our utilities business comprises businesses that transmit, distribute, and in certain circumstances, generate power. In addition, the Company has operations in the renewables area. These efforts include projects primarily in wind and solar.

Operating and Economic Risks — The Company operates in several developing economies where macroeconomic conditions are usually more volatile than developed economies. Deteriorating market conditions often expose the Company to the risk of decreased earnings and cash flows due to, among other factors, adverse fluctuations in the commodities and foreign currency spot markets. Additionally, credit markets around the globe continue to tighten their standards, which could impact our ability to finance growth projects through access to capital markets. Currently, the Company has a below-investment grade rating from Standard & Poor's of BB+, Fitch of BB+, and Moody's of Ba1. This could affect the Company's ability to finance new and/or existing development projects at competitive interest rates. As of December 31, 2018, the Company had $1.2 billion of unrestricted cash and cash equivalents.

During 2018, 68% of our revenue was generated outside the U.S. and a significant portion of our international operations is conducted in developing countries. We continue to invest in several developing countries to expand our existing platform and operations. International operations, particularly the operation, financing and development of projects in developing countries, entail significant risks and uncertainties, including, without limitation:

- economic, social and political instability in any particular country or region;
- inability to economically hedge energy prices;
- volatility in commodity prices;
- adverse changes in currency exchange rates;
- government restrictions on converting currencies or repatriating funds;
- unexpected changes in foreign laws, regulatory framework, or in trade, monetary or fiscal policies;
- high inflation and monetary fluctuations;
- restrictions on imports of coal, oil, gas or other raw materials required by our generation businesses to operate;
- threatened or consummated expropriation or nationalization of our assets by foreign governments;
- unwillingness of governments, government agencies, similar organizations or other counterparties to honor their commitments;
- unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to subsidiaries of the Company and economically unfavorable to counterparties, against such counterparties, whether such counterparties are governments or private parties;
- inability to obtain access to fair and equitable political, regulatory, administrative and legal systems;
- adverse changes in government tax policy;
- difficulties in enforcing our contractual rights, enforcing judgments, or obtaining a just result in local jurisdictions; and
- potentially adverse tax consequences of operating in multiple jurisdictions.

Any of these factors, individually or in combination with others, could materially and adversely affect our business, results of operations and financial condition. In addition, our Latin American operations experience volatility in revenue and earnings which have caused and are expected to cause significant volatility in our results of operations and cash flows. The volatility is caused by regulatory and economic difficulties, political instability, indexation of certain PPAs to fuel prices, and currency fluctuations being experienced in many of these countries. This volatility reduces the predictability and enhances the uncertainty associated with cash flows from these businesses.

Our inability to predict, influence or respond appropriately to changes in law or regulatory schemes, including any inability to obtain reasonable increases in tariffs or tariff adjustments for increased expenses, could adversely impact our results of operations or our ability to meet publicly announced projections or analysts' expectations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly our utility businesses where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including, but not limited to:

- changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs;
- changes in the definition or determination of controllable or noncontrollable costs;
- adverse changes in tax law;
- changes in the definition of events which may or may not qualify as changes in economic equilibrium;
- changes in the timing of tariff increases;
- other changes in the regulatory determinations under the relevant concessions; or

- changes in environmental regulations, including regulations relating to GHG emissions in any of our businesses.

Any of the above events may result in lower margins for the affected businesses, which can adversely affect our results of operations.

Foreign Currency Risks — AES operates businesses in many foreign countries and such operations could be impacted by significant fluctuations in foreign currency exchange rates. Fluctuations in currency exchange rate between U.S. dollar and the following currencies could create significant fluctuations in earnings and cash flows: the Argentine peso, the Brazilian real, the Dominican Republic peso, the Euro, the Chilean peso, the Colombian peso, and the Philippine peso.

Concentrations — Due to the geographical diversity of its operations, the Company does not have any significant concentration of customers or sources of fuel supply. Several of the Company's generation businesses rely on PPAs with one or a limited number of customers for the majority of, and in some cases all of, the relevant businesses' output over the term of the PPAs. However, no single customer accounted for 10% or more of total revenue in 2018, 2017 or 2016.

The cash flows and results of operations of our businesses depend on the credit quality of our customers and the continued ability of our customers and suppliers to meet their obligations under PPAs and fuel supply agreements. If a substantial portion of the Company's long-term PPAs and/or fuel supply were modified or terminated, the Company would be adversely affected to the extent that it would be unable to replace such contracts at equally favorable terms.

27. RELATED PARTY TRANSACTIONS

Certain of our businesses in Panama and the Dominican Republic are partially owned by governments either directly or through state-owned institutions. In the ordinary course of business, these businesses enter into energy purchase and sale transactions, and transmission agreements with other state-owned institutions which are controlled by such governments. At two of our generation businesses in Mexico, the offtakers exercise significant influence, but not control, through representation on these businesses' Boards of Directors. These offtakers are also required to hold a nominal ownership interest in such businesses. In Chile, we provide capacity and energy under contractual arrangements to our investment which is accounted for under the equity method of accounting. Additionally, the Company provides certain support and management services to several of its affiliates under various agreements.

The Company's Consolidated Statements of Operations included the following transactions with related parties for the periods indicated (in millions):

Years Ended December 31,	2018	2017	2016
Revenue—Non-Regulated	$ 1,533	$ 1,297	$ 1,100
Cost of Sales—Non-Regulated	342	220	210
Interest income	14	8	4
Interest expense	54	36	39

The following table summarizes the balances receivable from and payable to related parties included in the Company's Consolidated Balance Sheets as of the periods indicated (in millions):

December 31,	2018	2017
Receivables from related parties	$ 371	$ 250
Accounts and notes payable to related parties	754	727

The Company entered into an equity transaction with our related party, Linda Group, see Note 14—*Equity* for further information.

28. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly Financial Data — The following tables summarize the unaudited quarterly Condensed Consolidated Statements of Operations for the Company for 2018 and 2017 (amounts in millions, except per share data). Amounts have been restated to reflect discontinued operations in all periods presented and reflect all adjustments necessary in the opinion of management for a fair statement of the results for interim periods.

Quarter Ended 2018	Mar 31	Jun 30	Sep 30	Dec 31
Revenue	$ 2,740	$ 2,537	$ 2,837	$ 2,622
Operating margin	656	600	671	646
Income from continuing operations, net of tax (1)	778	224	192	155
Income (loss) from discontinued operations, net of tax (2)	(1)	192	(1)	26
Net income	$ 777	$ 416	$ 191	$ 181
Net income attributable to The AES Corporation	$ 684	$ 290	$ 101	$ 128
Basic earnings per share:				
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.04	$ 0.15	$ 0.15	$ 0.15
Income from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	0.29	—	0.04
Net income attributable to The AES Corporation common stockholders	$ 1.04	$ 0.44	$ 0.15	$ 0.19
Diluted earnings per share:				
Income from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ 1.03	$ 0.15	$ 0.15	$ 0.15
Income from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	0.29	—	0.04
Net income attributable to The AES Corporation common stockholders	$ 1.03	$ 0.44	$ 0.15	$ 0.19
Dividends declared per common share	$ 0.13	$ —	$ 0.13	$ 0.27

Quarter Ended 2017	Mar 31	Jun 30	Sep 30	Dec 31
Revenue	$ 2,581	$ 2,613	$ 2,693	$ 2,643
Operating margin	557	623	640	645
Income (loss) from continuing operations, net of tax (3)	97	142	235	(622)
Income (loss) from discontinued operations, net of tax (4)	1	8	26	(664)
Net income (loss)	$ 98	$ 150	$ 261	$ (1,286)
Net income (loss) attributable to The AES Corporation	$ (24)	$ 53	$ 152	$ (1,342)
Basic earnings (loss) per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (0.04)	$ 0.08	$ 0.22	$ (1.03)
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	—	0.01	(1.00)
Net income (loss) attributable to The AES Corporation common stockholders	$ (0.04)	$ 0.08	$ 0.23	$ (2.03)
Diluted earnings per share:				
Income (loss) from continuing operations attributable to The AES Corporation common stockholders, net of tax	$ (0.04)	$ 0.08	$ 0.22	$ (1.03)
Income (loss) from discontinued operations attributable to The AES Corporation common stockholders, net of tax	—	—	0.01	(1.00)
Net income (loss) attributable to The AES Corporation common stockholders	$ (0.04)	$ 0.08	$ 0.23	$ (2.03)
Dividends declared per common share	$ 0.12	$ —	$ 0.12	$ 0.25

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(1) Includes pre-tax gains on sales of business interests of $788 million, $89 million and $128 million, in the first, second and fourth quarters of 2018, respectively, and pre-tax losses of $21 million in the third quarter of 2018 (See Note 23—*Held-for-Sale and Dispositions*), pre-tax impairment expense of $92 million, $74 million and $42 million, in the second, third and fourth quarters of 2018, respectively (See Note 20—*Asset Impairment Expense*), other-than-temporary impairment of Guacolda of $144 million in the fourth quarter of 2018 (See Note 7—*Investments in and Advances to Affiliates*), SAB 118 charges to finalize the provisional estimate of one-time transition tax on foreign earnings of $33 million and $161 million in the third and fourth quarters of 2018, respectively, and a SAB 118 income tax benefit to finalize the provisional estimate of remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $77 million in the fourth quarter of 2018 (See Note 21—*Income Taxes*).

(2) Includes gain on sale of Eletropaulo of $199 million in the second quarter of 2018 (See Note 22—*Discontinued Operations*).

(3) Includes provisional tax expense related to a one-time transition tax on foreign earnings of $675 million and the remeasurement of deferred tax assets and liabilities to the lower corporate tax rate of $39 million in the fourth quarter of 2017 (See Note 21—*Income Taxes*), pre-tax impairment expense of $168 million, $90 million and $277 million, in the first, second and fourth quarters of 2017, respectively (See Note 20—*Asset Impairment Expense*), and pre-tax losses on sales of business interests of $48 million in second quarter of 2017 (See Note 23—*Held-for-Sale and Dispositions*).

(4) Includes loss on deconsolidation of Eletropaulo of $611 million in the fourth quarter of 2017 (See Note 22—*Discontinued Operations*).

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The Company maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports that the Company files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosures.

The Company carried out the evaluation required by Rules 13a-15(b) and 15d-15(b), under the supervision and with the participation of our management, including the CEO and CFO, of the effectiveness of our “disclosure controls and procedures” (as defined in the Exchange Act Rules 13a-15(e) and 15d-15(e)). Based upon this evaluation, the CEO and CFO concluded that as of December 31, 2018, our disclosure controls and procedures were effective.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and
- provide reasonable assurance that unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements are prevented or detected timely.

Management, including our CEO and CFO, does not expect that our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. In addition, any evaluation of the effectiveness of controls is subject to risks that those internal controls may become inadequate in future periods because of changes in business conditions, or that the degree of compliance with the policies or procedures deteriorates.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2018.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report, which appears herein.

Changes in Internal Control Over Financial Reporting:

There were no changes that occurred during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of The AES Corporation:

Opinion on Internal Control over Financial Reporting

We have audited The AES Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, The AES Corporation (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "financial statements"), and our report dated February 26, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Tysons, Virginia
February 26, 2019

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following information is incorporated by reference from the Registrant's Proxy Statement for the Registrant's 2019 Annual Meeting of Stockholders which the Registrant expects will be filed on or around March 6, 2019 (the "2019 Proxy Statement"):

- information regarding the directors required by this item found under the heading *Board of Directors*;
- information regarding AES' Code of Ethics found under the heading *Additional Governance Matters - AES Code of Business Conduct and Corporate Governance Guidelines*;
- information regarding compliance with Section 16 of the Exchange Act required by this item found under the heading *Additional Governance Matters - Other Governance Information - Section 16(a) Beneficial Ownership Reporting Compliance*; and
- information regarding AES' Financial Audit Committee found under the heading *Board and Committee Governance Matters - Financial Audit Committee (the "Audit Committee").*

Certain information regarding executive officers required by this Item is presented as a supplementary item in Part I hereof (pursuant to Instruction 3 to Item 401(b) of Regulation S-K). The other information required by this Item, to the extent not included above, will be contained in our 2019 Proxy Statement and is herein incorporated by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 402 of Regulation S-K is contained in the 2019 Proxy Statement under "Director Compensation" and "Executive Compensation" (excluding the information under the caption "Report of the Compensation Committee") and is incorporated herein by reference.

The information required by Item 407(e)(5) of Regulation S-K is contained under the caption "Report of the Compensation Committee Report" of the Proxy Statement. Such information shall not be deemed to be "filed."

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

(a) Security Ownership of Certain Beneficial Owners and Management.

See the information contained under the heading *Security Ownership of Certain Beneficial Owners, Directors, and Executive Officers* of the 2019 Proxy Statement, which information is incorporated herein by reference.

(b) Securities Authorized for Issuance under Equity Compensation Plans.

The following table provides information about shares of AES common stock that may be issued under AES' equity compensation plans, as of December 31, 2018:

Securities Authorized for Issuance under Equity Compensation Plans (As of December 31, 2018)

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders [1]	9,794,600 [2]	$ 12.36	14,534,999
Equity compensation plans not approved by security holders	—	—	—
Total	9,794,600	$ 12.36	14,534,999

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(1) The following equity compensation plans have been approved by The AES Corporation's Stockholders:

(A) The AES Corporation 2003 Long Term Compensation Plan was adopted in 2003 and provided for 17,000,000 shares authorized for issuance thereunder. In 2008, an amendment to the Plan to provide an additional 12,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 29,000,000. In 2010, an additional amendment to the Plan to provide an additional 9,000,000 shares was approved by AES' stockholders, bringing the total authorized shares to 38,000,000. In 2015, an additional amendment to the Plan to provide an additional 7,750,000 shares was approved by AES' stockholders, bringing the total authorized shares to 45,750,000. The weighted average exercise price of Options outstanding under this plan included in Column (b) is $12.36 (excluding performance stock units, restricted stock units and director stock units), with 14,534,999 shares available for future issuance.

(B) The AES Corporation Second Amended and Restated Deferred Compensation Plan for directors provided for 2,000,000 shares authorized for issuance. Column (b) excludes the Director stock units granted thereunder. In conjunction with the 2010 amendment to the 2003 Long Term Compensation Plan, ongoing award issuance from this plan was discontinued in 2010 as Director stock units will be issued from the 2003 Long Term Compensation Plan. Any remaining shares under this plan, which are not reserved for issuance under outstanding awards, are not available for future issuance and thus the amount of 105,341 shares is not included in Column (c) above.

(2) Includes 4,366,156 (of which 592,813 are vested and 3,773,343 are unvested) shares underlying PSU and RSU awards (assuming 2016 PSU median performance and 2017 and 2018 PSUs maximum performance), 1,646,376 shares underlying Director stock unit awards, and 3,782,068 shares issuable upon the exercise of Stock Option grants, for an aggregate number of 9,794,600 shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information regarding related party transactions required by this item is included in the 2019 Proxy Statement found under the headings *Transactions with Related Persons* and *Board and Committee Governance Matters* and are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item 14 is included in the 2019 Proxy Statement under the headings *Information Regarding The Independent Registered Public Accounting Firm, Audit Fees, Audit Related Fees, and Pre-Approval Policies and Procedures* and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULE

(a) Financial Statements.

(b) Exhibits.

3.1	Sixth Restated Certificate of Incorporation of The AES Corporation is incorporated herein by reference to Exhibit 3.1 of the Company's Form 10-K for the year ended December 31, 2008.
3.2	By-Laws of The AES Corporation, as amended and incorporated herein by reference to Exhibit 3.1 of the Company's Form 8-K/A filed on December 2, 2015.
4	There are numerous instruments defining the rights of holders of long-term indebtedness of the Registrant and its consolidated subsidiaries, none of which exceeds ten percent of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any of such agreements to the Commission upon request. Since these documents are not required filings under Item 601 of Regulation S-K, the Company has elected to file certain of these documents as Exhibits 4.(a)—4.(q).
4.(a)	Senior Indenture, dated as of December 8, 1998, between The AES Corporation and Wells Fargo Bank, National Association, as successor to Bank One, National Association (formerly known as The First National Bank of Chicago) is incorporated herein by reference to Exhibit 4.01 of the Company's Form 8-K filed on December 11, 1998 (SEC File No. 001-12291).
4.(b)	Ninth Supplemental Indenture, dated as of April 3, 2003, between The AES Corporation and Wells Fargo Bank, National Association (as successor by consolidation to Wells Fargo Bank Minnesota, National Association) is incorporated herein by reference to Exhibit 4.6 of the Company's Form S-4 filed on December 7, 2007.
4.(c)	Sixteenth Supplemental Indenture, dated April 30, 2013, between The AES Corporation and Wells Fargo Bank, N.A., as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on April 30, 2013 (SEC File No. 001-12291).
4.(d)	Seventeenth Supplemental Indenture, dated March 7, 2014, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 7, 2014.
4.(e)	Nineteenth Supplemental Indenture, dated April 6, 2015, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on April 6, 2015.
4.(f)	Twentieth Supplemental Indenture, dated May 25, 2016, between The AES Corporation and Wells Fargo Bank, N.A. as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on May 25, 2016.
4.(g)	Twenty-First Supplemental Indenture, dated August 28, 2017, between The AES Corporation and Deutsche Bank Trust Company, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on August 28, 2017.
4.(h)	Twenty-Second Supplemental Indenture, dated March 15, 2018, between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 15, 2018.
4.(i)	Twenty-Fourth Supplemental Indenture, dated March 15, 2018 between The AES Corporation and Deutsche Bank Trust Company Americas, as Trustee is incorporated herein by reference to Exhibit 4.1 of the Company's Form 8-K filed on March 21, 2018.
10.1	The AES Corporation Profit Sharing and Stock Ownership Plan are incorporated herein by reference to Exhibit 4(c)(1) of the Registration Statement on Form S-8 (Registration No. 33-49262) filed on July 2, 1992. (P)
10.2	The AES Corporation Incentive Stock Option Plan of 1991, as amended, is incorporated herein by reference to Exhibit 10.30 of the Company's Form 10-K for the year ended December 31, 1995 (SEC File No. 00019281). (P)
10.3	Applied Energy Services, Inc. Incentive Stock Option Plan of 1982 is incorporated herein by reference to Exhibit 10.31 of the Registration Statement on Form S-1 (Registration No. 33-40483). (P)
10.4	Deferred Compensation Plan for Executive Officers, as amended, is incorporated herein by reference to Exhibit 10.32 of Amendment No. 1 to the Registration Statement on Form S-1 (Registration No. 33-40483). (P)
10.5	Deferred Compensation Plan for Directors, as amended and restated, on February 17, 2012 is incorporated herein by reference to Exhibit 10.5 of the Company's Form 10-K for the year ended December 31, 2012.
10.6	The AES Corporation Stock Option Plan for Outside Directors, as amended and restated, on December 7, 2007 is incorporated herein by reference to Exhibit 10.6 of the Company's Form 10-K for the year ended December 31, 2012.
10.7	The AES Corporation Supplemental Retirement Plan is incorporated herein by reference to Exhibit 10.63 of the Company's Form 10-K for the year ended December 31, 1994 (SEC File No. 00019281). (P)
10.7A	Amendment to The AES Corporation Supplemental Retirement Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.9.A of the Company's Form 10-K for the year ended December 31, 2007.
10.8	The AES Corporation 2001 Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company's Form 10-K for the year ended December 31, 2000 (SEC File No. 001-12291).
10.9	Second Amended and Restated Deferred Compensation Plan for Directors is incorporated herein by reference to Exhibit 10.13 of the Company's Form 10-K for the year ended December 31, 2000 (SEC File No. 001-12291).
10.10	The AES Corporation 2001 Non-Officer Stock Option Plan is incorporated herein by reference to Exhibit 10.12 of the Company's Form 10-K for the year ended December 31, 2002 (SEC File No. 001-12291).
10.10A	Amendment to the 2001 Stock Option Plan and 2001 Non-Officer Stock Option Plan, dated March 13, 2008 is incorporated herein by reference to Exhibit 10.12A of the Company's Form 10-K for the year ended December 31, 2007.
10.11	The AES Corporation 2003 Long Term Compensation Plan, as Amended and Restated, dated April 23, 2015, is incorporated herein by reference to Exhibit 99.1 of the Company's Form 8-K filed on April 23, 2015.
10.12	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan (Outside Directors) is incorporated herein by reference to Exhibit 10.2 of the Company's Form 8-K filed on April 27, 2010.

10.13	Form of AES Performance Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.13 of the Company's Form 10-K for the year ended December 31, 2015.
10.14	Form of AES Restricted Stock Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.14 of the Company's Form 10-K for the year ended December 31, 2015.
10.15	Form of AES Performance Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2015.
10.16	Form of AES Nonqualified Stock Option Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.4 of the Company's Form 10-Q for the quarter ended June 30, 2015.
10.17	Form of AES Performance Cash Unit Award Agreement under The AES Corporation 2003 Long Term Compensation Plan is incorporated herein by reference to Exhibit 10.17 of the Company's Form 10-K for the year ended December 31, 2015.
10.18	The AES Corporation Restoration Supplemental Retirement Plan, as amended and restated, dated December 29, 2008 is incorporated herein by reference to Exhibit 10.15 of the Company's Form 10-K for the year ended December 31, 2008.
10.18A	Amendment to The AES Corporation Restoration Supplemental Retirement Plan, dated December 9, 2011 is incorporated herein by reference to Exhibit 10.17A of the Company's Form 10-K for the year ended December 31, 2012.
10.19	The AES Corporation International Retirement Plan, as amended and restated on December 29, 2008 is incorporated herein by reference to Exhibit 10.16 of the Company's Form 10-K for the year ended December 31, 2008.
10.19A	Amendment to The AES Corporation International Retirement Plan, dated December 9, 2011 is incorporated herein by reference to Exhibit 10.18A of the Company's Form 10-K for the year ended December 31, 2012.
10.20	The AES Corporation Severance Plan, as amended and restated on August 4, 2017 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 10-Q for the quarter ended June 30, 2017.
10.21	The AES Corporation Amended and Restated Executive Severance Plan dated October 5, 2018 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 10-Q for the quarter ended September 30, 2018.
10.22	The AES Corporation Performance Incentive Plan, as Amended and Restated on April 23, 2015 is incorporated herein by reference to Exhibit 99.2 of the Company's Form 8-K filed on April 23, 2015.
10.23	The AES Corporation Deferred Compensation Program For Directors dated February 17, 2012 is incorporated herein by reference to Exhibit 10.22 of the Company's Form 10-K filed on December 31, 2011.
10.24	The AES Corporation Employment Agreement with Andrés Gluski is incorporated herein by reference to Exhibit 99.3 of the Company's Form 8-K filed on December 31, 2008.
10.25	Mutual Agreement, between Andrés Gluski and The AES Corporation dated October 7, 2011 is incorporated herein by reference to Exhibit 10.2 of the Company's Form 10-Q for the period ended September 30, 2011.
10.26	Form of Retroactive Consent to Provide for Double-Trigger Change-In-Control Transactions is incorporated herein by reference to Exhibit 10.7 of the Company's Form 10-Q for the period ended June 30, 2015.
10.27	Amendment No. 3, dated as of July 26, 2013 to the Fifth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2010 is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on July 29, 2013.
10.27A	Sixth Amended and Restated Credit and Reimbursement Agreement dated as of July 26, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof, Citibank, N.A., as Administrative Agent and Collateral Agent, Citigroup Global Markets Inc., as Lead Arranger and Book Runner, Banc of America Securities LLC, as Lead Arranger and Book Runner and Co-Syndication Agent, Barclays Capital, as Lead Arranger and Book Runner and Co-Syndication Agent, RBS Securities Inc., as Lead Arranger and Book Runner and Co-Syndication Agent and Union Bank, N.A., as Lead Arranger and Book Runner and Co-Syndication Agent is incorporated herein by reference to Exhibit 10.1.A of the Company's Form 8-K filed on July 29, 2013.
10.27B	Appendices and Exhibits to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 29, 2013 is incorporated herein by reference to Exhibit 10.1.B of the Company's Form 8-K filed on July 29, 2013.
10.27C	Amendment No. 1, dated as of May 6, 2016 to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 23, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof and Citibank, N.A. as Administrative Agent and Collateral Agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 9, 2016.
10.27D	Amendment No. 2, dated as of June 28, 2017, to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 26, 2013 among The AES Corporation, a Delaware corporation, the Banks listed on the signature pages thereof and Citibank, N.A. as Administrative Agent and Collateral Agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on June 29, 2017.
10.27E	Annex A. to Amendment No. 2, dated as of June 28, 2017, to the Sixth Amended and Restated Credit and Reimbursement Agreement, dated as of July 26, 2013 is incorporated herein by reference to 10.1.A of the Company's Form 8-K filed on June 29, 2017.
10.28	Collateral Trust Agreement dated as of December 12, 2002 among The AES Corporation, AES International Holdings II, Ltd., Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, an individual trustee is incorporated herein by reference to Exhibit 4.2 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.29	Security Agreement dated as of December 12, 2002 made by The AES Corporation to Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.3 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.30	Credit Agreement dated as of May 24, 2017 among The AES Corporation, as borrower, the bank listed therein and Bank of America, N.A., as administrative agent is incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K filed on May 24, 2017.
10.31	Charge Over Shares dated as of December 12, 2002 between AES International Holdings II, Ltd. and Wilmington Trust Company, as corporate trustee and Bruce L. Bisson, as individual trustee is incorporated herein by reference to Exhibit 4.4 of the Company's Form 8-K filed on December 17, 2002 (SEC File No. 001-12291).
10.32	Agreement and Plan of Merger, dated as of February 19, 2017, by and among AES Lumos Holdings, LLC, PIP5 Lumos LLC, AES Lumos Merger Sub, LLC, PIP5 Lumos MS LLC, FTP Power LLC and Fir Tree Solar LLC is incorporated herein by reference to Exhibit 10.31 of the Company's Form 10-K for the year ending December 31, 2016.
10.33	Consulting Agreement by and between The AES Corporation and Brian A. Miller dated February 26, 2018 is incorporated herein by reference to Exhibit 10.33 of the Company's Form 10-K for the year ending December 31, 2017.
21.1	Subsidiaries of The AES Corporation (filed herewith).
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP (filed herewith).
24	Powers of Attorney (filed herewith).
31.1	Rule 13a-14(a)/15d-14(a) Certification of Andrés Gluski (filed herewith).

31.2	Rule 13a-14(a)/15d-14(a) Certification of Gustavo Pimenta (filed herewith).
32.1	Section 1350 Certification of Andrés Gluski (filed herewith).
32.2	Section 1350 Certification of Gustavo Pimenta (filed herewith).
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith).
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith).
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith).
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith).
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith).

(c) Schedule

Schedule I—Financial Information of Registrant

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

THE AES CORPORATION
(Company)

Date: February 26, 2019

By: /s/ ANDRÉS GLUSKI

Name: Andrés Gluski

President, Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the Company and in the capacities and on the dates indicated.

Name	Title	Date
* **Andrés Gluski**	President, Chief Executive Officer (Principal Executive Officer) and Director	February 26, 2019
* **Charles L. Harrington**	Director	February 26, 2019
* **Kristina M. Johnson**	Director	February 26, 2019
* **Tarun Khanna**	Director	February 26, 2019
* **Holly K. Koeppel**	Director	February 26, 2019
* **James H. Miller**	Director	February 26, 2019
* **Alain Monié**	Director	February 26, 2019
* **John B. Morse**	Chairman of the Board and Lead Independent Director	February 26, 2019
* **Moises Naim**	Director	February 26, 2019
* **Jeffrey W. Ubben**	Director	February 26, 2019
/s/ GUSTAVO PIMENTA **Gustavo Pimenta**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2019
/s/ SARAH R. BLAKE **Sarah R. Blake**	Vice President and Controller (Principal Accounting Officer)	February 26, 2019

*By: /s/ PAUL L. FREEDMAN — February 26, 2019

Attorney-in-fact

THE AES CORPORATION AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedules other than that listed above are omitted as the information is either not applicable, not required, or has been furnished in the consolidated financial statements or notes thereto included in Item 8 hereof.

See Notes to Schedule I

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
BALANCE SHEETS

	December 31,	
	2018	2017
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 19	$ 10
Accounts and notes receivable from subsidiaries	285	143
Prepaid expenses and other current assets	31	27
Total current assets	335	180
Investment in and advances to subsidiaries and affiliates	6,834	8,239
Office Equipment:		
Cost	27	27
Accumulated depreciation	(19)	(18)
Office equipment, net	8	9
Other Assets:		
Other intangible assets, net of accumulated amortization	3	3
Deferred financing costs, net of accumulated amortization of $4 and $2, respectively	4	5
Deferred income taxes	24	289
Other assets	2	2
Total other assets	33	299
Total assets	$ 7,210	$ 8,727
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable	$ 15	$ 18
Accounts and notes payable to subsidiaries	74	381
Accrued and other liabilities	206	246
Senior notes payable—current portion	5	5
Total current liabilities	300	650
Long-term Liabilities:		
Senior notes payable	3,650	4,625
Accounts and notes payable to subsidiaries	28	967
Other long-term liabilities	24	20
Total long-term liabilities	3,702	5,612
Stockholders' equity:		
Common stock	8	8
Additional paid-in capital	8,154	8,501
Accumulated deficit	(1,005)	(2,276)
Accumulated other comprehensive loss	(2,071)	(1,876)
Treasury stock	(1,878)	(1,892)
Total stockholders' equity	3,208	2,465
Total liabilities and equity	$ 7,210	$ 8,727

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT STATEMENTS OF OPERATIONS

For the Years Ended December 31,	2018	2017	2016
		(in millions)	
Revenue from subsidiaries and affiliates	$ 36	$ 28	$ 14
Equity in earnings of subsidiaries and affiliates	1,909	630	(615)
Interest income	39	49	19
General and administrative expenses	(142)	(158)	(144)
Other income	25	5	7
Other expense	—	(554)	(65)
Loss on extinguishment of debt	(171)	(92)	(14)
Interest expense	(220)	(317)	(344)
Income (loss) before income taxes	1,476	(409)	(1,142)
Income tax benefit (expense)	(273)	(752)	12
Net income (loss)	$ 1,203	$ (1,161)	$ (1,130)

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016

	2018	2017	2016
		(in millions)	
NET INCOME (LOSS)	$ 1,203	$ (1,161)	$ (1,130)
Foreign currency translation activity:			
Foreign currency translation adjustments, net of income tax benefit of $2, $11 and $1, respectively	(214)	18	117
Reclassification to earnings, net of $0 income tax for all periods	(21)	643	992
Total foreign currency translation adjustments, net of tax	(235)	661	1,109
Derivative activity:			
Change in derivative fair value, net of income tax benefit (expense) of $16, $13 and $(5), respectively	(64)	(14)	2
Reclassification to earnings, net of income tax benefit (expense) of $(13), $1 and $1, respectively	78	37	28
Total change in fair value of derivatives, net of tax	14	23	30
Pension activity:			
Prior service cost for the period, net of income tax expense of $1, $1 and $5, respectively	(2)	1	9
Change in pension adjustments due to net actuarial gain (loss) for the period, net of income tax benefit (expense) of $(1), $6 and $10, respectively	2	(20)	(22)
Reclassification of earnings, net of income tax benefit (expense) of $(2), $(126) and $2, respectively	7	248	1
Total change in unfunded pension obligation	7	229	(12)
OTHER COMPREHENSIVE INCOME (LOSS)	(214)	913	1,127
COMPREHENSIVE INCOME (LOSS)	$ 989	$ (248)	$ (3)

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I CONDENSED FINANCIAL INFORMATION OF PARENT
STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2018	2017	2016
		(in millions)	
Net cash provided by operating activities	$ 409	$ 148	$ 818
Investing Activities:			
Proceeds from the sale of business interests, net of expenses	1,222	—	—
Investment in and net advances to subsidiaries	(216)	(339)	(650)
Return of capital	242	243	247
Additions to property, plant and equipment	(13)	(13)	(12)
Net cash provided by (used in) investing activities	1,235	(109)	(415)
Financing Activities:			
(Repayments) Borrowings under the revolver, net	(207)	207	—
Borrowings of notes payable and other coupon bearing securities	1,000	1,025	500
Repayments of notes payable and other coupon bearing securities	(1,933)	(1,353)	(808)
Loans from (Repayments to) subsidiaries	(143)	309	183
Purchase of treasury stock	—	—	(79)
Proceeds from issuance of common stock	7	1	1
Common stock dividends paid	(344)	(317)	(290)
Payments for deferred financing costs	(11)	(12)	(12)
Distributions to noncontrolling interests	—	—	(2)
Other financing	(5)	(7)	(3)
Net cash used in financing activities	(1,636)	(147)	(510)
Effect of exchange rate changes on cash	1	6	1
Increase (Decrease) in cash and cash equivalents	9	(102)	(106)
Cash and cash equivalents, beginning	10	112	218
Cash and cash equivalents, ending	$ 19	$ 10	$ 112
Supplemental Disclosures:			
Cash payments for interest, net of amounts capitalized	$ 232	$ 282	$ 296
Cash payments for income taxes, net of refunds	$ 10	$ 2	$ 6

See Notes to Schedule I.

THE AES CORPORATION

SCHEDULE I
NOTES TO SCHEDULE I

1. Application of Significant Accounting Principles

The Schedule I Condensed Financial Information of the Parent includes the accounts of The AES Corporation (the "Parent Company") and certain holding companies.

ACCOUNTING FOR SUBSIDIARIES AND AFFILIATES — The Parent Company has accounted for the earnings of its subsidiaries on the equity method in the financial information.

INCOME TAXES — Positions taken on the Parent Company's income tax return which satisfy a more-likely-than-not threshold will be recognized in the financial statements. The income tax expense or benefit computed for the Parent Company reflects the tax assets and liabilities on a stand-alone basis and the effect of filing a consolidated U.S. income tax return with certain other affiliated companies as well as effects of U.S. tax law reform enacted in 2017.

ACCOUNTS AND NOTES RECEIVABLE FROM SUBSIDIARIES — Amounts have been shown in current or long-term assets based on terms in agreements with subsidiaries, but payment is dependent upon meeting conditions precedent in the subsidiary loan agreements.

2. Debt

Senior and Secured Notes and Loans Payable ($ in millions)

	Interest Rate	Maturity	December 31, 2018	December 31, 2017
Senior Unsecured Note	8.00%	2020	$ —	$ 228
Senior Unsecured Note	7.38%	2021	—	690
Drawings on secured credit facility	LIBOR + 2.00%	2021	—	207
Senior Unsecured Note	4.00%	2021	500	—
Senior Secured Term Loan	LIBOR + 1.75%	2022	366	521
Senior Unsecured Note	4.50%	2023	500	—
Senior Unsecured Note	4.88%	2023	713	713
Senior Unsecured Note	5.50%	2024	63	738
Senior Unsecured Note	5.50%	2025	544	573
Senior Unsecured Note	6.00%	2026	500	500
Senior Unsecured Note	5.13%	2027	500	500
Unamortized (discounts)/premiums & debt issuance (costs)			(31)	(40)
Subtotal			$ 3,655	$ 4,630
Less: Current maturities			(5)	(5)
Total			$ 3,650	$ 4,625

FUTURE MATURITIES OF RECOURSE DEBT — As of December 31, 2018 scheduled maturities are presented in the following table (in millions):

December 31,	Annual Maturities
2019	$ 5
2020	5
2021	505
2022	350
2023	1,213
Thereafter	1,608
Unamortized (discount)/premium & debt issuance (costs)	(31)
Total debt	$ 3,655

3. Dividends from Subsidiaries and Affiliates

Cash dividends received from consolidated subsidiaries were $1.9 billion, $1.2 billion and $1 billion for the years ended December 31, 2018, 2017, and 2016, respectively. For the year ended December 31, 2018, $1.2 billion of the dividends paid to the Parent Company are derived from the sale of business interests and are classified as an investing activity for cash flow purposes. All other dividends are classified as operating activities. There were no cash dividends received from affiliates accounted for by the equity method for the years ended December 31, 2018, 2017, and 2016.

4. Guarantees and Letters of Credit

GUARANTEES — In connection with certain of its project financing, acquisition and power purchase agreements, the Parent Company has expressly undertaken limited obligations and commitments, most of which will only be effective or will be terminated upon the occurrence of future events. These obligations and commitments, excluding those collateralized by letter of credit and other obligations discussed below, were limited as of December 31, 2018 by the terms of the agreements, to an aggregate of approximately $712 million, representing 34 agreements with individual exposures ranging up to $157 million. These amounts exclude normal and customary representations and warranties in agreements for the sale of assets (including ownership in associated legal entities) where the associated risk is considered to be nominal.

LETTERS OF CREDIT — At December 31, 2018, the Parent Company had $78 million in letters of credit outstanding under the senior secured credit facility, representing 23 agreements with individual exposures up to $49 million, and $368 million in letters of credit outstanding under the senior unsecured credit facility, representing 10 agreements with individual exposures ranging from $1 million to $247 million. During 2018, the Parent Company paid letter of credit fees ranging from 1% to 3% per annum on the outstanding amounts.

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AES EXECUTIVE LEADERSHIP TEAM

Andrés Gluski
President & Chief Executive Officer

Manuel Perez Dubuc
Senior Vice President,
Global New Energy Solutions

Julian Nebreda
Senior Vice President
& President, South America SBU

Bernerd Da Santos
Executive Vice President
& Chief Operating Officer

Gustavo Pimenta
Executive Vice President
& Chief Financial Officer

Leonardo Moreno
Senior Vice President,
Chief Strategy & Risk Officer

Paul Freedman
Senior Vice President, General Counsel
& Corporate Secretary

Sanjeev Addala
Chief Information Digital Officer

Lisa Krueger
Senior Vice President
& President, US and Utilities SBU

Tish Mendoza
Senior Vice President of Global Human Resources & Internal Communications and Chief Human Resource Officer

Juan Ignacio Rubiolo
Senior Vice President
& President, MCAC SBU

AES BOARD OF DIRECTORS

John B. Morse Jr. (Chairman)
Retired Senior Vice President Finance and CFO Washington Post Company; former Partner Waterhouse (now PricewaterhouseCoopers); former Trustee and President Emeritus of the College Foundation of the University of Virginia

Janet Davidson
Former Executive Vice President; Quality Customer Care Alcatel Lucent S.A.

Andrés Gulski
AES President & Chief Executive Officer

Charles Harrington
Chairman and CEO of Parsons Corporation

Kristina Johnson
Chancellor, State of New York University System; former CEO of Cube Hydro Partners; former Undersecretary for energy at the Department of Energy; former Provost and Senior Vice President for Academic Affairs at the John Hopkins University

Tarun Khanna
Jorge Paulo Lemann Professor at the Harvard Business School

Holly K. Koeppel
Former Managing Partner and Co-Head of Corsair Infrastructure Management, L.P.

James Miller
Former Chairman of PPL Corporation; former Executive Vice President of USEC Inc.; President for two ABB Group subsidiaries

Alain Monie
CEO of Ingram Micro

Moisés Naím
Distinguished Fellow in the International Economics Program at the Carnegie Endowment for International Peace and international columnist and broadcaster; Former Editor in Cheif for Foreign Policy magazine; Former Minister of Industry and Trade and the Central Bank for Venezuela; former Executive Director for the World Bank

Jeffrey Ubben
Founder and former CEO and CIO of ValueAct Capital

COMPANY INFORMATION

Corporate Office
The AES Corporation
4300 Wilson Boulevard
Arlington, VA 22203
USA
703.522.1315

Website
www.aes.com @TheAESCorp

AES LISTED NYSE

Stock Information
Common stock of The AES Corporation trades under the symbol AES. The AES Corporation is proud to meet the listing requirements of the NYSE, the world's leading equities market.

Number of Shareholders
As of December 31, 2018 there were approximately 3,919 AES shareholders of record and 662,298,096 shares of AES common stock outstanding.

Transfer Agent
The AES Corporation has designated Computershare Investor Services ("Computershare") to be its transfer agent for AES common stock.

Please contact Computershare if you need assistance with lost or stolen AES stock certificates directly held by you, issues related to dividend checks, address changes, name changes and stock transfers.

By mail:
Computershare
P.O. Box 505000
Lousiville, KY 40233

Overnight:
Computershare
462 South 4th Street, Suite 1600
Lousville, KY 40233-9814
877.373.6374
www.computershare.com

Independent Auditors
Ernst & Young LLP

Investors
Please visit the Investors section of the AES website at www.aes.com, or you may contact a member of the AES Investor Relations team:
General: invest@aes.com
Ahmed Pasha, Vice President,
Investor Relations: 703.682.6451

Media Inquiries
General: mediainquiries@aes.com
Amy Ackerman, Manager, External
Communications: 703.682.6399

AES Code of Conduct
AES is committed to demonstrating the highest standards of business ethics in all that we do. To that end, AES has adopted a Code of Conduct, which is available on our website.

we are the energy

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