NRG Energy Inc.

First Quarter 2017 Earnings Presentation

May 2, 2017

Safe Harbor

Forward-Looking Statements

In addition to historical information, the information presented in this communication includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act. These statements involve estimates, expectations, projections, goals, assumptions, known and unknown risks and uncertainties and can typically be identified by terminology such as “may,” “should,” “could,” “objective,” “projection,” “forecast,” “goal,” “guidance,” “outlook,” “expect,” “intend,” “seek,” “plan,” “think,” “anticipate,” “estimate,” “predict,” “target,” “potential” or “continue” or the negative of these terms or other comparable terminology. Such forward-looking statements include, but are not limited to, statements about the anticipated benefits of acquisitions, the Company’s future revenues, income, indebtedness, capital structure, plans, expectations, objectives, projected financial performance and/or business results and other future events, and views of economic and market conditions.

Although NRG believes that its expectations are reasonable, it can give no assurance that these expectations will prove to be correct, and actual results may vary materially. Factors that could cause actual results to differ materially from those contemplated herein include, among others, GenOn’s and certain of its subsidiaries’ ability to continue as a going concern, general economic conditions, hazards customary in the power production industry and power generation operations, weather conditions (including wind and solar conditions), competition in wholesale power markets, the volatility of energy and fuel prices, failure of customers to perform under contracts, changes in the wholesale power markets, the effectiveness of our risk management policies and procedures, changes in government regulations, the condition of capital markets generally, our ability to borrow funds and access capital markets, unanticipated outages at our generation facilities, adverse results in current and future litigation, failure to identify, execute or successfully implement acquisitions, repowerings or asset sales, our ability to implement value enhancing improvements to plant operations and companywide processes, our ability to proceed with projects under development or the inability to complete the construction of such projects on schedule or within budget, risks related to project siting, financing, construction, permitting, government approvals and the negotiation of project development agreements, our ability to progress development pipeline projects, the inability to maintain or create successful partnering relationships, our ability to operate our businesses efficiently including NRG Yield, our ability to retain retail customers, our ability to realize value through our commercial operations strategy and the creation of NRG Yield, the ability to successfully integrate businesses of acquired companies, our ability to realize anticipated benefits of transactions (including expected cost savings and other synergies) or the risk that anticipated benefits may take longer to realize than expected, our ability to close the Drop Down transactions with NRG Yield, and our ability to execute our capital allocation plan. Debt and share repurchases may be made from time to time subject to market conditions and other factors, including as permitted by United States securities laws. Furthermore, any common stock dividend is subject to available capital and market conditions.

NRG undertakes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. The adjusted EBITDA and free cash flow guidance are estimates as of May 2, 2017. These estimates are based on assumptions the company believed to be reasonable as of that date. NRG disclaims any current intention to update such guidance, except as required by law. The foregoing review of factors that could cause NRG’s actual results to differ materially from those contemplated in the forward-looking statements included in this Earnings Presentation should be considered in connection with information regarding risks and uncertainties that may affect NRG's future results included in NRG's filings with the Securities and Exchange Commission at www.sec.gov.

Agenda

Business Review
Mauricio Gutierrez, President and CEO

Financial Update
Kirk Andrews, EVP and CFO

Closing Remarks
Mauricio Gutierrez, President and CEO

Q&A

Q1 Results and Full Year Outlook

Q1 Business Highlights

Reaffirming Full Year Guidance; Q1 Results Impacted by Lower Hedge Margin

- Top decile safety performance
- Q1 Adjusted EBITDA of $412 MM
- Full year results weighted toward summer months

Continued Focus on Three Strategic Priorities

- Streamlining cost structure
- Portfolio optimization: 1.6 GW deactivations / mothballs expected in 1H17
- Continue to manage to target corporate credit metrics

Executing on Growth Opportunities

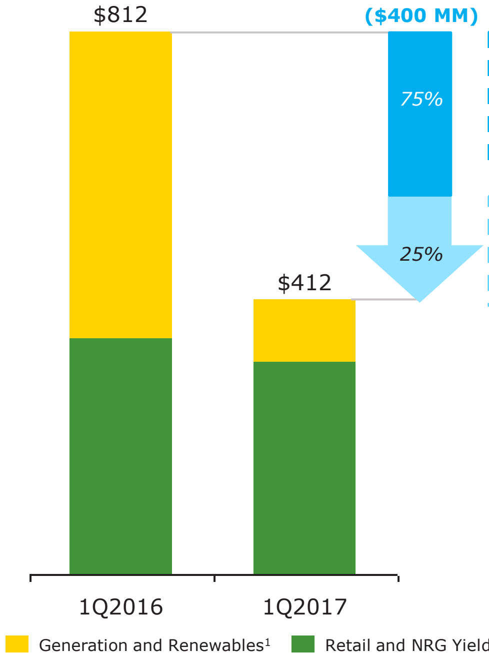
- Completed drop down of Utah Solar and Agua Caliente[2] assets
- Offered remaining 25% interest in NRG Wind TE Holdco to NRG Yield
- Carlsbad PPA finalized; construction began February 2017

Business Review Committee Process Underway

Year over Year Results and Drivers

($ millions)

Adjusted EBITDA: $400 MM Decrease Y/Y



Included in Guidance:
- Roll off of higher priced hedges
- Lower capacity revenue
- GenOn hedge monetization
- Emissions credits

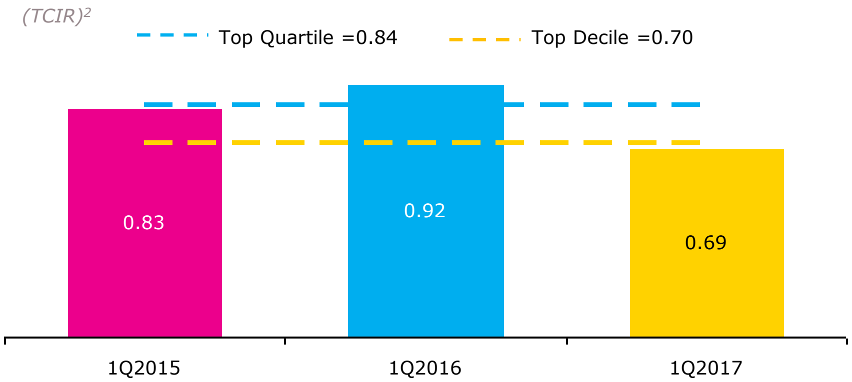
Variance to Guidance:
- Mild weather and lower wind/solar resource
- Advisory fees

Q1 Results Impacted by Lower Energy Margins and Mild Weather; Reaffirming Full Year Guidance Range

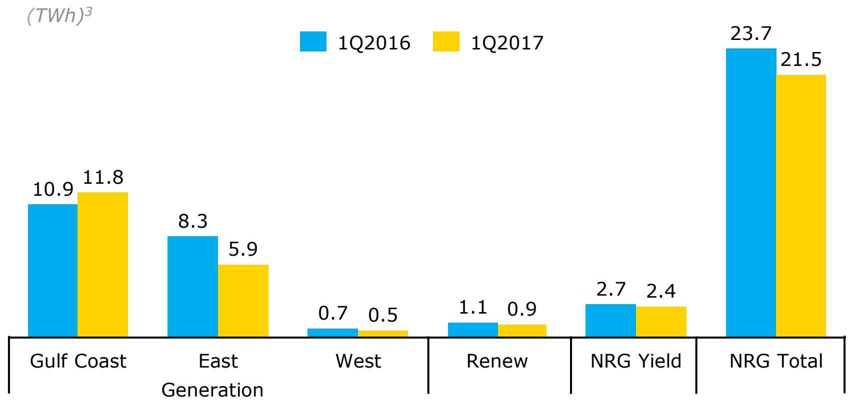
[1] Generation Segment includes Corp/Eliminations of ($41 MM) in 1Q16 and ($41 MM) in 1Q17; [2] Agua Caliente is 51% owned by NRG Consolidated, of which 16% was dropped down to NRG Yield

Operational Metrics

Safety[1]



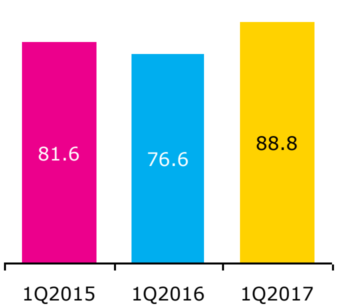
Production



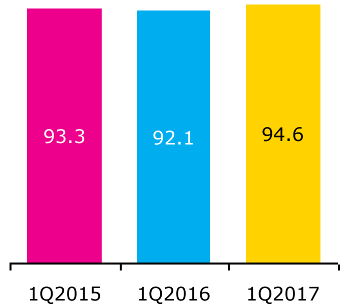
EAF and In the Money Availability

(%)

EAF

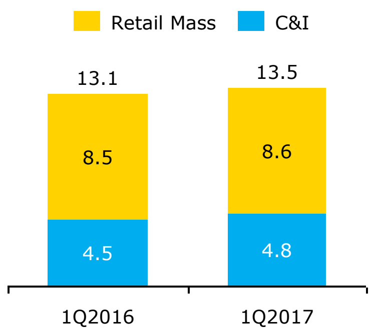


IMA[4]

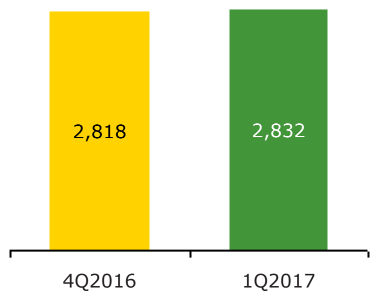


Retail Operations

Sales (TWh)



Mass Recurring Customers[5] (000s)



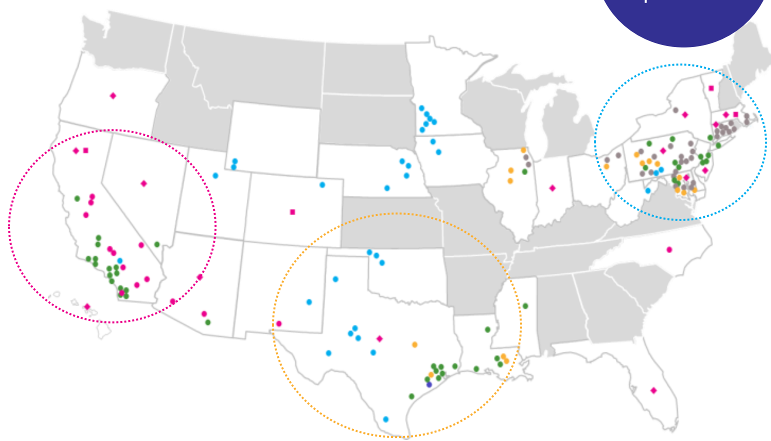
Top Decile Safety and Strong Operational Performance Continues

[1] Excludes Goal Zero, NRG Home Services and residential solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items; Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods; [4] Refer to Appendix slide 26; [5] Excludes C&I and residential solar customers; mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas

NRG Regional Strategies and Key Market Drivers

NRG Portfolio

49[2] GWs diverse portfolio



West

- ↑ Aggressive Renewable Portfolio Standards
- ↑ Need for ramping capacity
- ↑ Preferred resource contracts
- ↓ Weakening merchant dynamics

Renewables | Fast Start Gas
Distributed Resources

Gulf

- ↑ Load growth continues (2+% LTM[1])
- ↑ Potential for retirements
- ↑ Newbuild delays
- ↓ Increased reliance on intermittent resources
- ↓ Continued wind build-out
- ↓ Lack of scarcity prices

Integrated Wholesale - Retail Platform

East

- ↑ Capacity market framework rewards reliability
- ↑ Uneconomic units continue to retire
- ↓ Stagnant load growth
- ↓ Efforts for out-of-market contracts continue

Reliability (Capacity Markets)
Maintain Energy Option

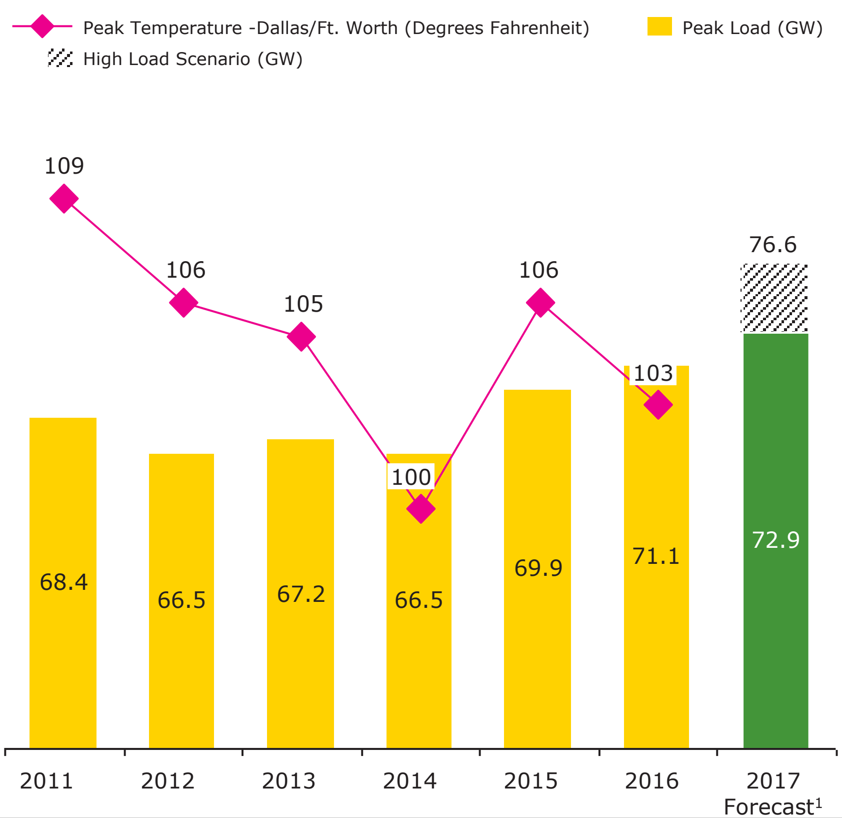
NRG Regional Strategies Tailored to Key Market Dynamics

[1] ERCOT year over year weather-normalized load growth; [2] Before non-controlling interest

Market Outlook - ERCOT

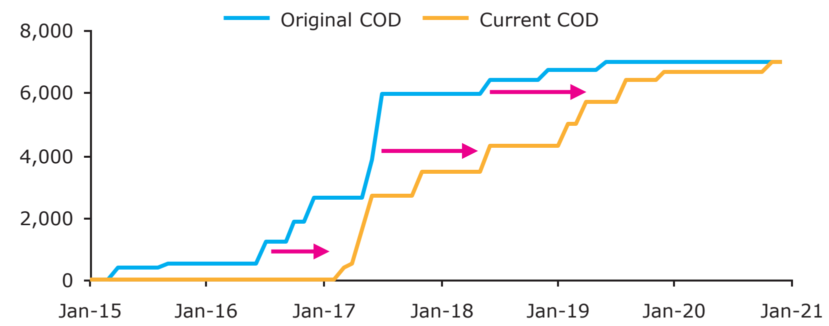
ERCOT Seeing Record, Sustained Increases in Load…

ERCOT Demand Growth[1]



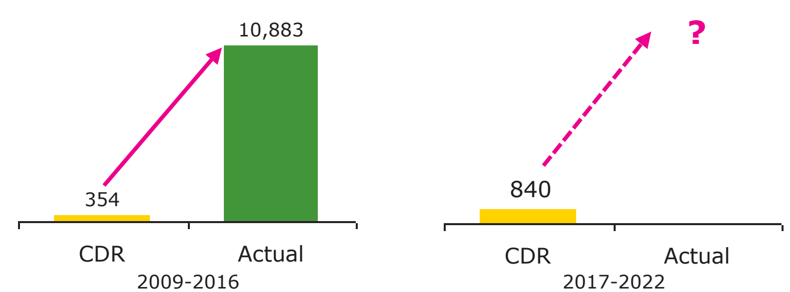
…While Delayed New Builds…

New Generation Commercial Operation Date[2] (MW)



…and Higher than Predicted Retirements Put Pressure on Reserve Margins

Retirements: CDR[3] vs Actual (MW)



ERCOT Market Continues To Tighten Through Record Loads, Retirement Risk, and Delayed New Builds

[1] ERCOT, NOAA. High load scenario based on ERCOT Summer 2017 Preliminary SARA Seasonal Load Adjustment of 3.7 GW; [2] ERCOT Generator Interconnection Status (GIS) report; graph includes only those assets that are listed as new thermal generation in the Dec 2016 CDR; [3] Report on the Capacity, Demand, and Reserves (CDR) in the ERCOT Region; Energy Velocity; Retirements represent retirements identified in prior and current CDRs

Market Outlook - Northeast

PJM: Shift to 100% Capacity Performance Market

Market Driver		Outlook
100% CP Requirement	↑	100% CP in 20/21 adds risk for ~17 GW of generation that cleared as base capacity in 19/20
Decreased Demand-side Participation	↑	Enhanced seasonal requirements add risk to ~10 GW of demand response and energy efficiency that cleared as base in 19/20
Zonal Transfer Ratios	↑	CETO[1]: CETL[2] ratios bolster potential for zonal price separation in COMED
Nuclear	↔	Unclear how subsidized IL nuclear stations will participate in capacity auction
Seasonal Aggregation	↓	Potential to pair summer and winter limited availability resources
Stagnant Load	↓	RTO Reliability Requirements down 2% year-on-year

Regulatory Landscape

- **Capacity Performance Implementation:**
  - Transition to 100% Capacity Performance rewards resources for reliability
- **Zero Emissions Credits (ZECs) Litigation in New York and Illinois:**
  - NRG and others filed federal court challenges against the unlawful interference in FERC -jurisdictional markets
  - Preliminary injunction sought in Illinois; awaiting ruling on motion to dismiss in New York
- **FERC Examining State Programs & Wholesale Markets:**
  - FERC increasingly assessing the impact of ZECs and other programs on the wholesale market

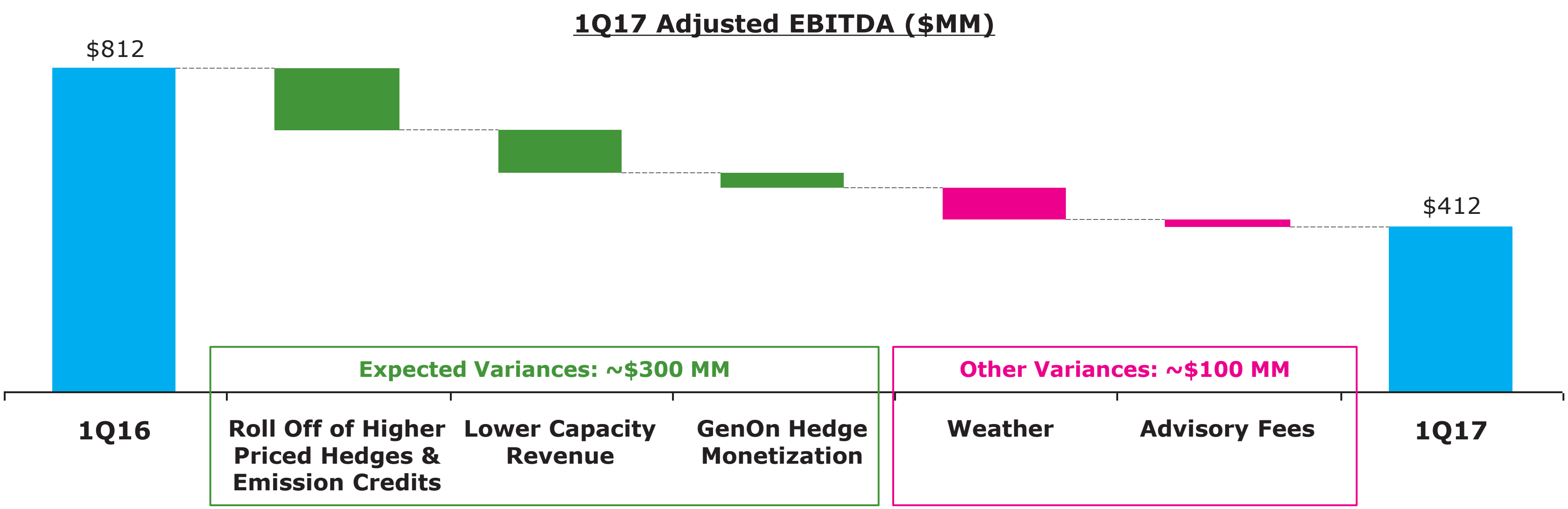
PJM Strengthened by 100% Capacity Performance but Out of Market Contracts Undermine the Integrity of Competitive Markets

[1] Capacity Emergency Transfer Objective; [2] Capacity Emergency Transfer Limit

Financial Update

Financial Summary

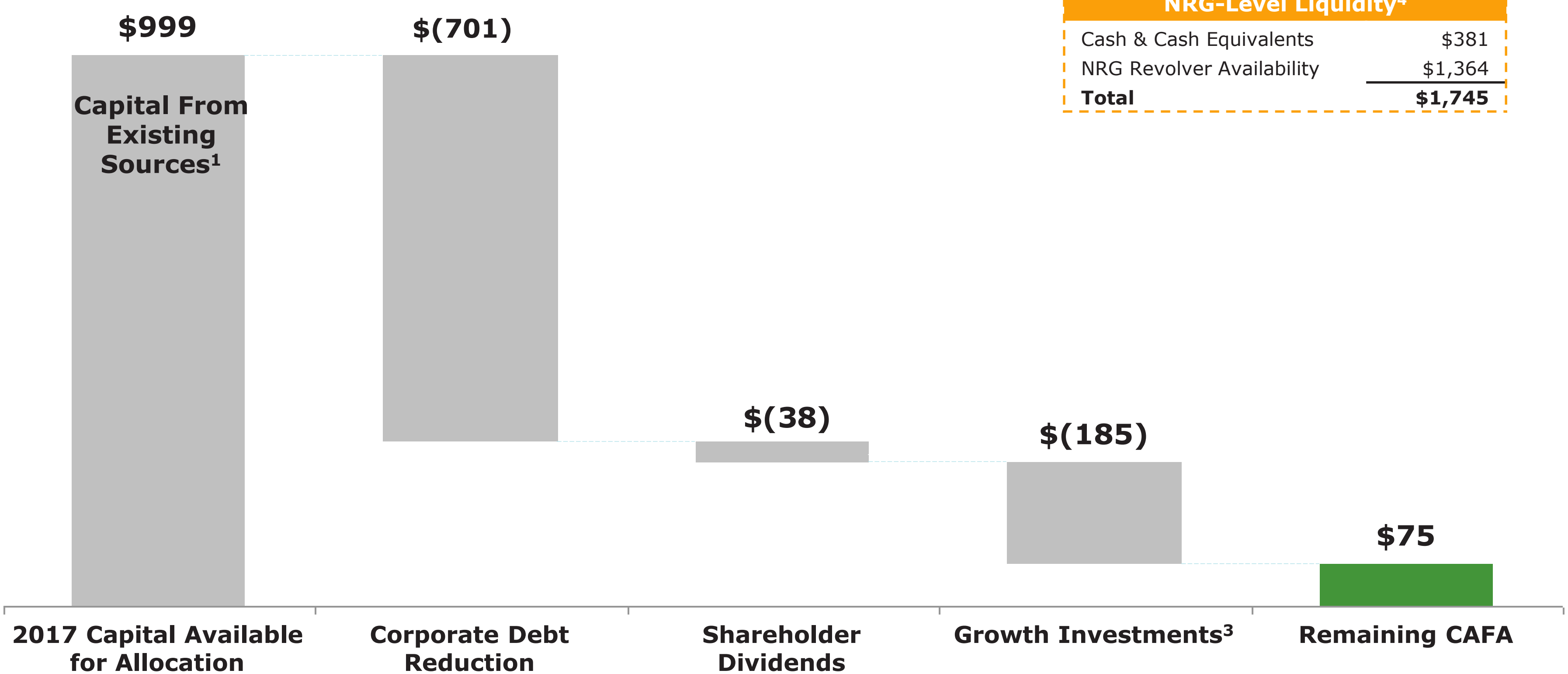
($ millions)	2017 1st Quarter	2017 Guidance Reaffirmed[3]
Generation & Renewables[1,2]	$95	$1,080 – $1,200
Retail	133	700 – 780
NRG Yield[2]	184	920
Adjusted EBITDA	**$412**	**$2,700 - $2,900**



[1] Includes Corporate Segment; [2] In accordance with GAAP, restated to reflect impact of Utah Solar and 31% of NRG's interest in Agua Caliente drop down to NRG Yield; [3] Reaffirming 2017 Adjusted EBITDA of $2,700 MM - $2,900 MM and Consolidated Free Cash Flow before Growth of $800 MM - $1,000 MM

2017 NRG-Level Capital Allocation

($ millions)



NRG-Level Liquidity[4]	
Cash & Cash Equivalents	$381
NRG Revolver Availability	$1,364
Total	**$1,745**

Retirement of 2018 Notes	$398
Reserve for Additional Debt Reduction	$200
Term Loan Amortization	$19
Midwest Gen Debt Amortization[2]	$80
Term Loan Refi Fees	$4

[1] Refer to slide 12 of 4Q16 earnings presentation. Capital from Existing Sources includes: 2016 YE cash & cash equivalents at NRG level of $570 MM less minimum cash reserves of $700 MM (net of $71 MM in NRG Level cash collateral postings) plus mid-point of NRG-level FCFbG guidance of $800 MM plus $128 MM of Agua Caliente project-level net financing proceeds closed on February 17, 2017 and $130 MM of gross proceeds from drop down of Utah solar assets and 16% interest in Agua Caliente to NRG Yield closed on March 27, 2017, prior to working capital adjustments; [2] Represents 2017 capacity revenue sold of $80 MM against $253 MM monetized in 2016; [3] Net of financing; [4] Includes $125 MM cash held at MWG which can be distributed to NRG Corporate with no restrictions; revolver availability represents $2.5 Bn revolving credit facility, less $1.0 Bn of letters of credit issued and $125 MM cash borrowed as of March 31, 2017

NRG's Capital Structure & Corporate Credit Metrics

($ millions)

Debt and Cash Balances As of 03/31/17

NRG Energy, Inc.		
	Consolidated	Recourse
Total Debt:	$19,477	$7,923[1]
Total Cash:	$1,513	$381

Dividends & Distributions

Project Company Management Service Payments

GenOn	NRG Yield	ROFO/ Other
Total Debt[2]: $2,749	Total Debt: $6,052	Total Debt: $2,881

~ $11.7 Bn

LEGEND

Recourse Debt

Non-Recourse Debt (Excluded Project Sub)

	2017E
	Post-Capital Allocation
Recourse Debt *(03/31/2017)*[1]	**$7,923**
2018 Maturity Reserve	(398)
2017 Term Loan Amortization	(15)
Additional Debt Reduction	(200)
Pro Forma Corporate Debt	**~$7,300**
Mid-Point Adj. EBITDA	$2,800
Less Adjusted EBITDA:	
GenOn[3]	(130)
NRG Yield	(920)
ROFO / Other[4]	(345)
Add:	
NRG Yield Distributions to NRG[5]	90
ROFO / Other Dividends to NRG[6]	110
Other Adjustments[7]	150
Total Recourse EBITDA	**$1,755**
Corporate Debt/Corporate EBITDA	**4.17x**
Cash & Cash Equivalents @ NRG-Level[8]	$645
Corporate Net Debt/Corporate EBITDA	**3.80x**

Maintaining Balance Sheet Metrics In-Line With Targets

[1] Includes NRG Energy Inc. term loan facility, senior notes, revolver, capital leases and tax exempt bonds; [2] Includes $125 MM outstanding cash balance on intercompany revolver; [3] Net of shared service payment by GenOn to NRG; [4] Includes Agua Caliente, Ivanpah, Midwest Generation, Yield eligible assets, Capistrano and other renewable assets; [5] Estimate based on NYLD dividends equivalent to $1.15/share annualized by Q4 and excludes impact of drop-down proceeds; [6] Distributions from NRG ROFO, MWG and other non-recourse project subsidiaries; [7] Reflects non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA; [8] NRG-Level cash of $570 MM as of 12/31/2016 plus remaining CAFA of $75 MM (see prior slide)

Closing Remarks

2017 Priorities

- ❑ **Reaffirming Full Year Guidance Ranges**
  - ☑ Q1 top decile safety performance

- ❑ **Finalize Comprehensive Resolution for GenOn** *(ongoing)*

- ❑ **Achieve Cost Efficiencies and Continue to Reposition Portfolio**
  - ❑ Business Review Committee process ongoing

- ❑ **Focus on Debt Reduction and Financial Flexibility**
  - ❑ On track managing to target credit metrics

- ❑ **Identify and Execute on Growth Opportunities with High Returns and Quick Capital Replenishment**
  - ☑ Closed drop down of 31% of NRG's interest Agua Caliente and Utah Solar Assets to NRG Yield
  - ❑ Offered to NRG Yield remaining 25% interest in NRG Wind TE Holdco

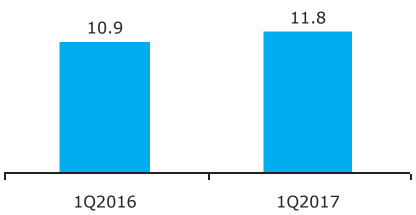
Q&A

Appendix: Operations

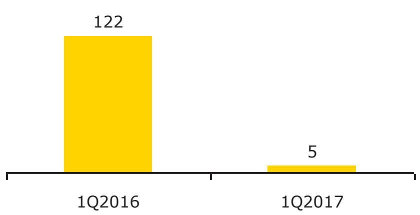
Year over Year Performance Drivers: Q1 Results

Gulf Coast

Generation (TWh)



EBITDA ($ MM)

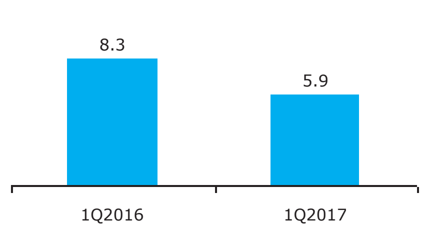


$117 MM lower Adjusted EBITDA due to:

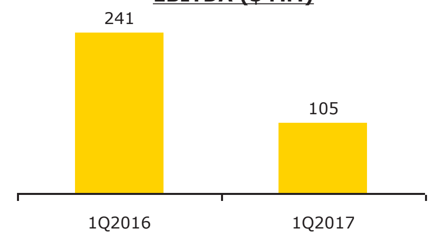
- ↓ Significantly lower hedged prices in 1Q17 vs 1Q16
- ↓ Lower capacity revenues from South Central assets cleared in PJM capacity auction
- ↑ Higher volumes sold due to higher open energy prices

East

Generation (TWh)



EBITDA ($ MM)

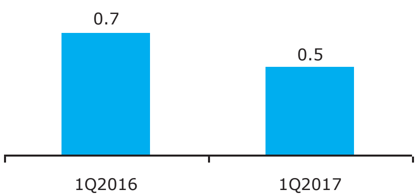


$136 MM lower Adjusted EBITDA due to:

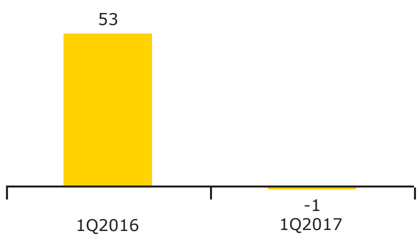
- ↓ Lower realized energy margins on lower hedged prices, lower capacity revenues from lower PJM pricing and 2016 asset sales
- ↑ Partially offset by favorable O&M following completion of conversion/environmental projects in 2016, deactivation of Huntley, and favorable maintenance due to reduced planned outages

West

Generation (TWh)



EBITDA ($ MM)

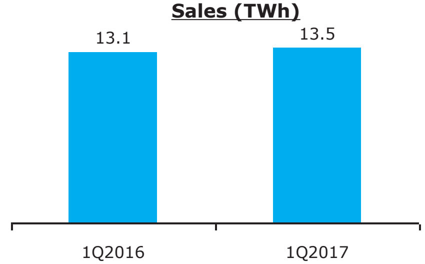


$54 MM lower Adjusted EBITDA due to:

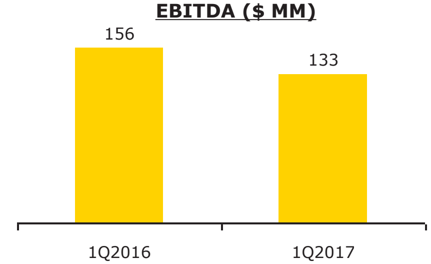
- ↓ One time 1Q16 $46 MM gain on sale of emissions credits
- ↓ Capacity contract expiration and subsequent retirements of Pittsburg and Encina assets
- ↑ Partially offset by favorable O&M due to timing of outages

Retail (Mass & C&I)

Sales (TWh)



EBITDA ($ MM)

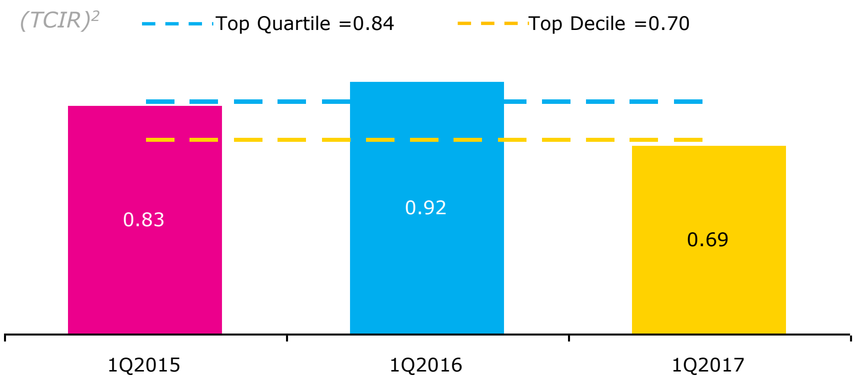


$23 MM lower Adjusted EBITDA due to:

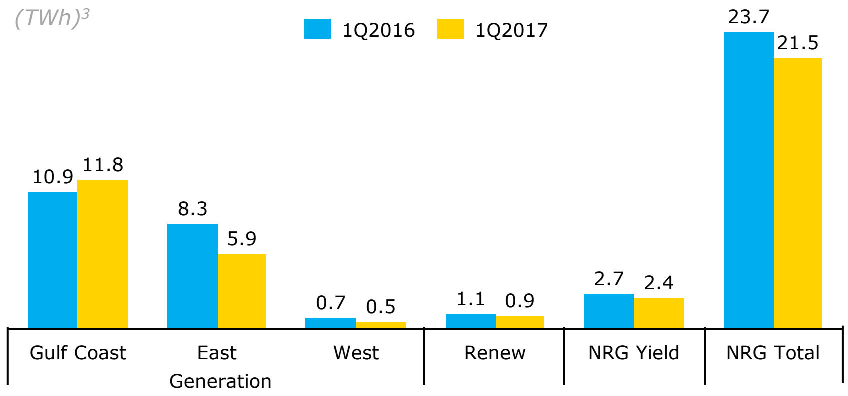
- ↓ Lower gross margins due to mild weather and customer mix
- ↑ Partially offset by increase in customer count and steady weather-normalized usage / customer

Generation: Operational Metrics

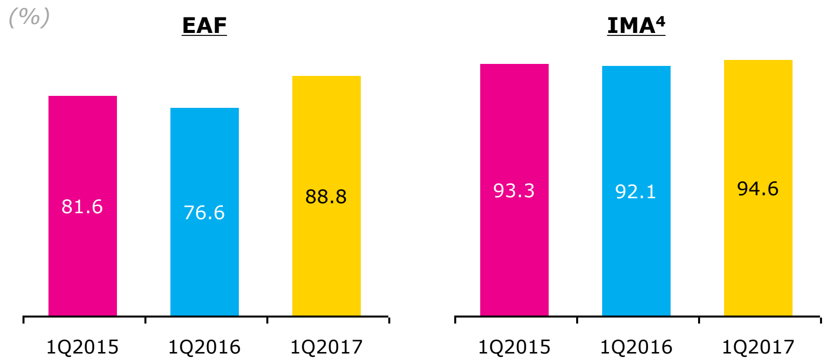
Safety[1]



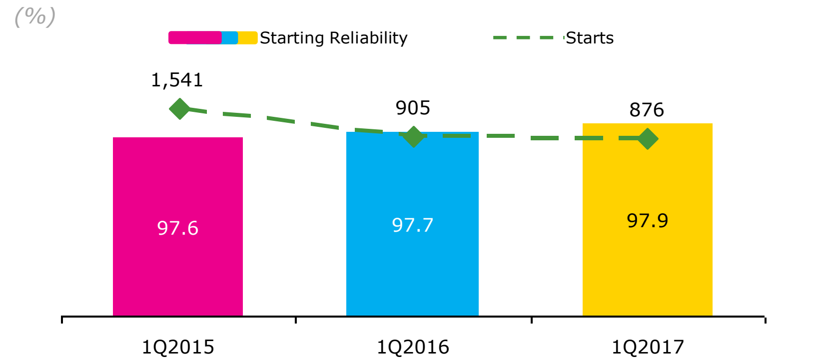
Production



EAF and In the Money Availability



Gas and Oil Starts and Reliability



Top Decile Safety and Strong Operational Performance Continues

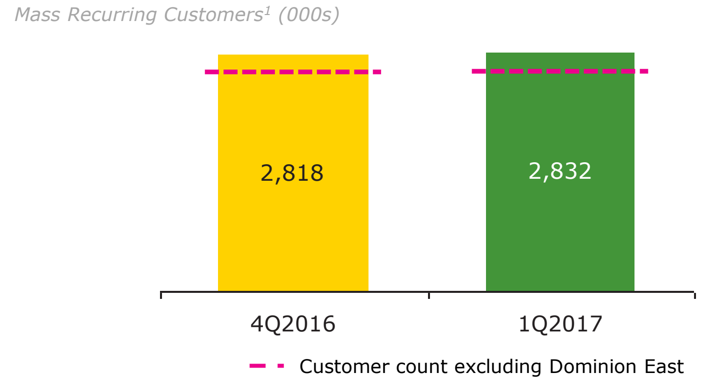
[1] Excludes Goal Zero, NRG Home Services and residential solar; top decile and top quartile based on Edison Electric Institute 2015 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [3] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with US GAAP accounting. Previous reports were pro-forma for acquisitions in prior periods; [4] Refer to Appendix slide 26

Retail: Operational Metrics

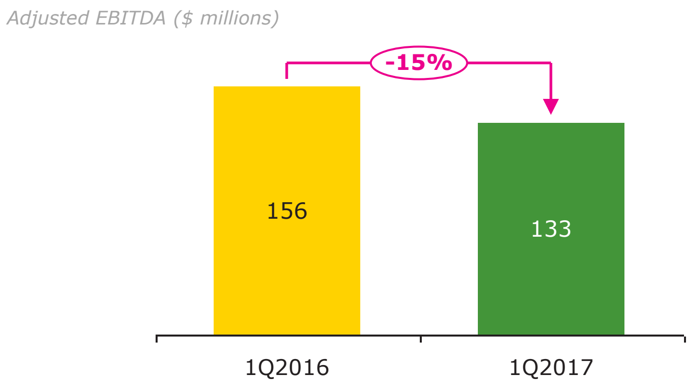
1st Quarter Summary

- Delivered solid earnings with $133 MM Adjusted EBITDA
- $19 MM in lower Q1 margins associated with weather
- Continued momentum in mass customer growth with a 14,000 increase during the quarter

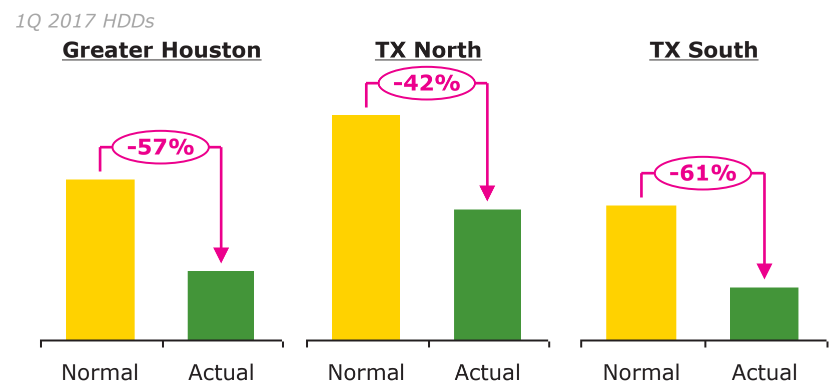
Expanded Mass Customer Count



EBITDA Results Lower Year over Year



Texas Heating Degree Days (HDD)[2] Substantially Below Normal



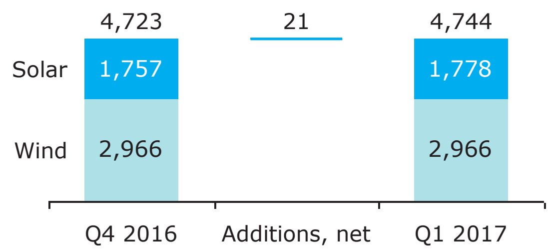
Mild Weather Created Challenges in Q1, But Retail Remains On Track Toward 2017 Guidance

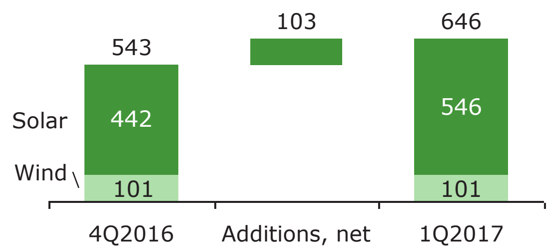
[1] Excludes C&I and NRG residential solar customers; mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas; [2] Heating Degree Day (HDD) represents the number of degrees that the mean temperature for a particular day is below 65 degrees Fahrenheit

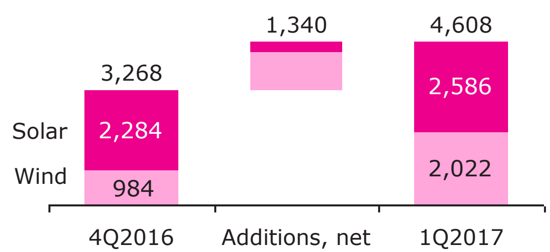
Renewables: Portfolio Update

Quarter over Quarter Change

(MW[1])







Key Q1 Updates

Operating Portfolio: 4,744 MW[1,2,3]

- ☑ Operations on 19 DG and Community solar projects across MN, CA, MA
- ☑ Added 310 MW of projects in queue to the 2.7 GW fleet in self operations

2017-2019 Backlog: 646 MW[4]

- ☑ Successfully contracted 3 HI projects with HECO (110 MW)
- ☑ Executed on Community Solar expansion in New York
- ☑ 364 MW Utility Scale (TX, HI); including 101 MW in construction
- ☑ 282 MW Community & DG (9 States); including 119 MW in construction

Utility–Scale and DG Pipeline: 4,608 MW[5]

- ☑ Increase reflects utility-scale origination in ISO-NE, ERCOT, CAISO
- ☑ Community Solar continued expansion across MN and NY
- ☑ DG growth across commercial, municipalities, and schools

Significant Scale and with a Substantial Pipeline for Future Growth

[1] 4.7 GW at NRG Consolidated, of which 2.9 GW is at NYLD; [2] MW amounts in AC; [3] NRG self-performs plant operations on 2.7 GW of the consolidated fleet of assets owned by NRG and NYLD and 224 MW on assets owned by third parties; [4] Backlog is defined as projects that are under construction, contracted, or awarded, and represents a higher level of execution certainty; [5] Pipeline is defined as projects that range from identified lead to shortlisted with an offtake and represents a lower level of execution certainty

Modernizing the Portfolio

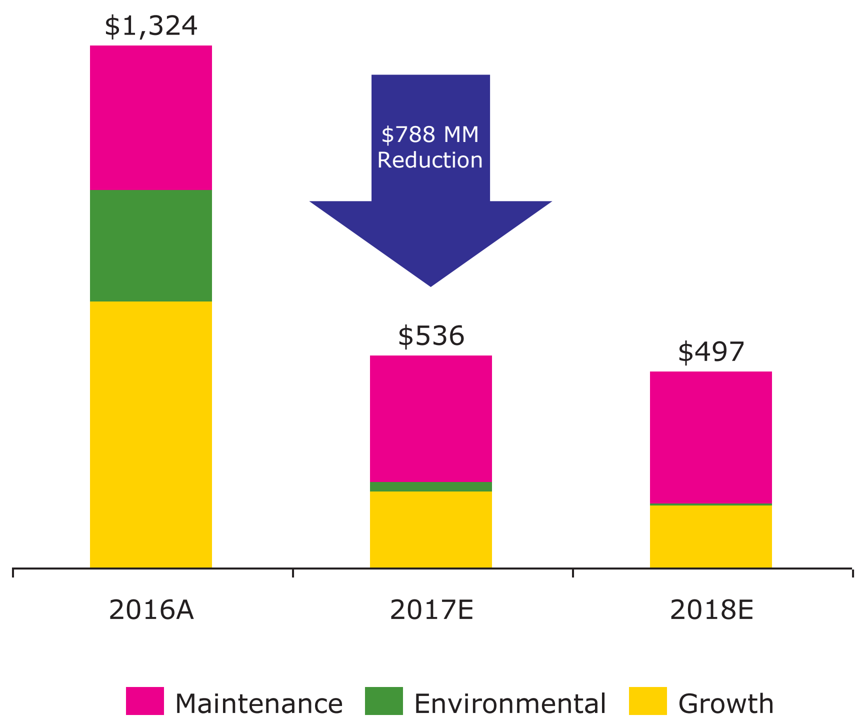
Delivering Major Projects

		MW	Project Description	Estimated COD
Growth Projects	Bacliff Peakers	360	New Generation	2Q 2017
	University of Pittsburgh Medical Center[1]		Heat & Power Combined	1Q 2018
	Buckthorn Solar	154	New Renewables	1Q 2018
	Carlsbad Peakers	527	New Generation	4Q 2018
	Hawaii Solar	110	New Renewables	2Q 2019
	Canal Peakers[2]	333	New Generation	2Q 2019
	Puente Peakers[2]	262	New Generation	2Q 2020

Significant Reduction in Capex in 2017

($ millions)

NRG Consolidated Capex

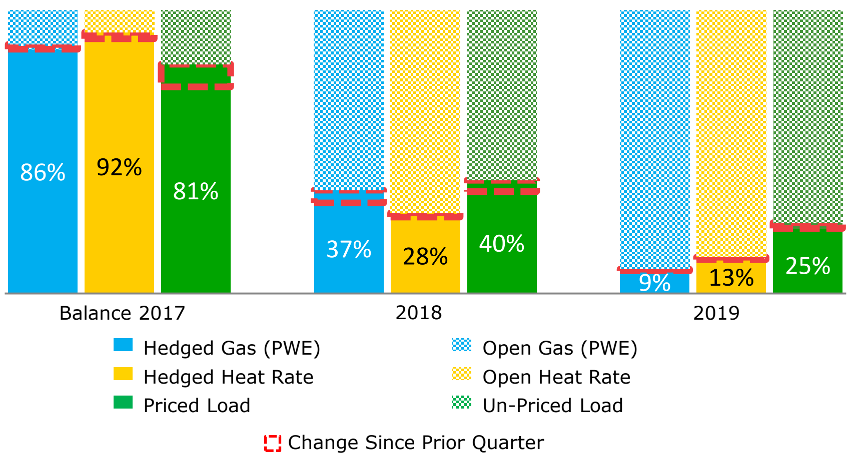


Portfolio Includes Both Conventional And Renewable Projects

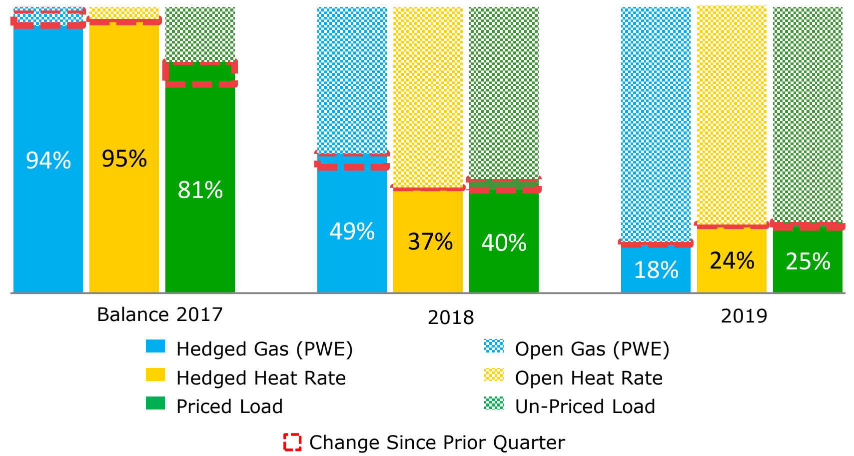
[1] NRG Yield acquisition; [2] Subject to applicable regulatory approvals and permits

Managing Commodity Price Risk

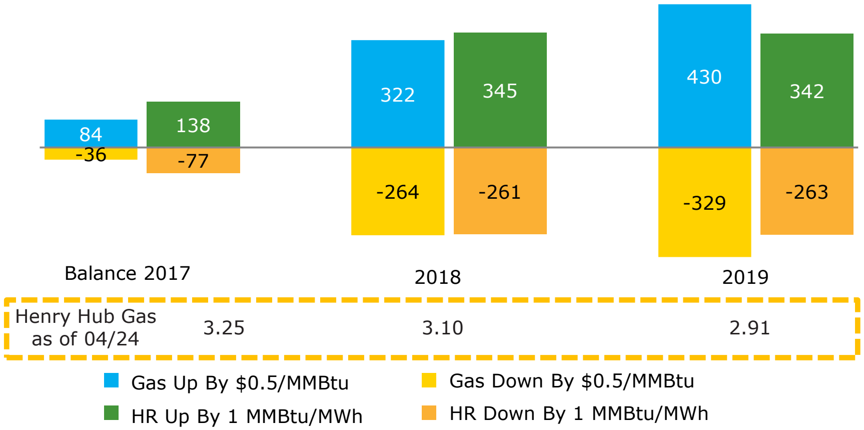
Total Portfolio Generation and Retail Hedge Position[1,2,5]



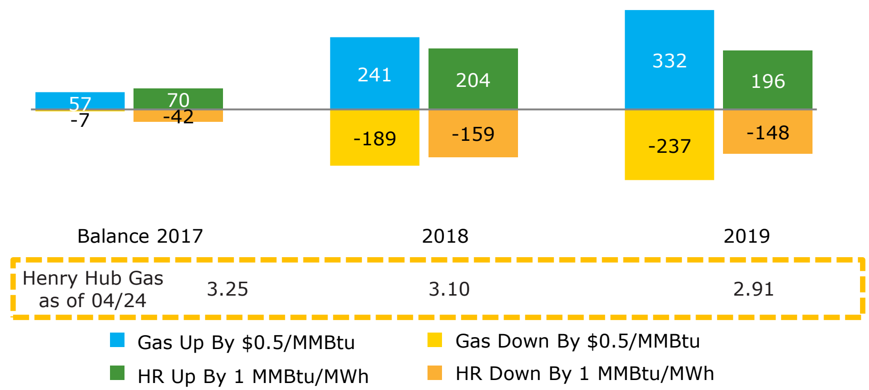
Coal and Nuclear Generation and Retail Hedge Position[1,2,4]



Total Portfolio Sensitivity to Gas Price and Heat Rate[1,3,5]



Coal and Nuclear Generation Sensitivity to Gas Price and Heat Rate[1,3]



[1] Portfolio as of 04/24/2017, Balance 2017 reflects April through December; [2] Retail priced load includes term load, hedged month-to-month load, and Indexed load; [3] Price sensitivity reflects gross margin change from $0.5/MMBtu gas price, 1 MMBtu/MWh heat rate move; [4] Coal hedge ratios are 101% and 45% for 2017 and 2018 respectively; [5] Total Portfolio includes wholesale merchant assets and related hedges

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Hedge Disclosure: Coal and Nuclear Operations

Coal & Nuclear Portfolio [1]	Texas and South Central			EAST			GENON [7]		
	Balance 2017	**2018**	**2019**	**Balance 2017**	**2018**	**2019**	**Balance 2017**	**2018**	**2019**
Net Coal and Nuclear Capacity (MW)[2]	6,250	6,250	6,250	7,465	7,465	7,465	4,198	4,198	4,198
Forecasted Coal and Nuclear Capacity (MW)[3]	4,804	4,334	3,977	3,644	3,017	2,227	2,029	1,759	1,294
Total Coal and Nuclear Sales (GWh)[4]	29,754	25,016	8,463	22,454	6,578	1,139	10,644	1,925	20
Percentage Coal and Nuclear Capacity Sold Forward[5]	94%	66%	24%	93%	25%	6%	80%	12%	0%
Total Forward Hedged Revenues [6]	$1,095	$897	$429	$765	$201	$28	$381	$62	$0
Weighted Average Hedged Price ($ per MWh)[6]	$36.80	$35.87	$50.71	$34.06	$30.58	NA	$35.83	$31.96	NA
Average Equivalent Natural Gas Price ($ per MMBtu)[6]	$3.60	$3.81	$4.92	$3.30	$2.97	NA	$3.35	$3.08	NA
Gross Margin Sensitivities									
Gas Price Sensitivity Up $0.50/MMBtu on Coal and Nuclear Units	$—	$42	$124	$64	$199	$207	$42	$121	$113
Gas Price Sensitivity Down $0.50/MMBtu on Coal and Nuclear Units	$32	($45)	($102)	($39)	($144)	($135)	($24)	($88)	($77)
Heat Rate Sensitivity Up 1 MMBtu/MWh on Coal and Nuclear Units	$22	$93	$88	$47	$111	$108	$28	$59	$55
Heat Rate Sensitivity Down 1 MMBtu/MWh on Coal and Nuclear Units	($8)	($75)	($67)	($34)	($84)	($80)	($21)	($46)	($43)

1 Portfolio as of 04/24/2017, Balance 2017 reflects April through December
2 Net Coal and Nuclear capacity represents nominal summer net MW capacity of power generated as adjusted for the Company's ownership position excluding capacity from inactive/mothballed units
3 Forecasted generation dispatch output (MWh) based on forward price curves as of 04/24/2017 which is then divided by number of hours in a given year to arrive at MW capacity; The dispatch takes into account planned and unplanned outage assumptions
4 Includes amounts under power sales contracts and natural gas hedges; the forward natural gas quantities are reflected in equivalent GWh based on forward market implied heat rate as of 04/24/2017 and then combined with power sales to arrive at equivalent GWh hedged; the Coal and Nuclear Sales include swaps and delta of options sold which is subject to change; actual value of options will include the impact of non-linear factors; For detailed information on the Company's hedging methodology through use of derivative instruments, see discussion in 2015 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities, to the Consolidated Financial Statements; Includes inter-segment sales from the Company's wholesale power generation business to the Retail Business
5 Percentage hedged is based on Total Coal and Nuclear sales as described above (4) divided by the forecasted Coal and Nuclear Capacity (3)
6 Represents all coal and nuclear sales, including energy revenue and demand charges
7 GenOn disclosure not additive to other regions

Commodity Prices

Forward Prices[1]	Bal-2017[2]	2018	2019	Annual Average for 2017-2019
NG Henry Hub ($/Mmbtu)	$3.25	$3.10	$2.91	$3.09
PRB 8800 ($/ton)	$11.84	$12.15	$12.35	$12.12
NAPP MG2938 ($/ton)	$45.78	$45.75	$47.50	$46.34
ERCOT Houston Onpeak ($/MWh)	$38.53	$35.68	$34.38	$36.19
ERCOT Houston Offpeak ($/MWh)	$24.81	$22.21	$20.88	$22.63
PJM West Onpeak ($/MWh)	$37.55	$37.88	$35.55	$36.99
PJM West Offpeak ($/MWh)	$26.25	$26.92	$25.69	$26.29

[1] Prices as of 04/24/2017
[2] Represents April through December months

Fuel Statistics

Domestic[1]	1st Quarter 2017	1st Quarter 2016
Coal Consumed (mm Tons)	5.6	5.5
PRB Blend	**88%**	**62%**
East	76%	55%
Gulf Coast	93%	71%
Bituminous	**7%**	**20%**
East	24%	36%
Lignite & Other	**5%**	**18%**
East	0%	9%
Gulf Coast	7%	29%
Cost of Coal ($/Ton)	**$ 35.52**	**$ 42.44**
Cost of Coal ($/mmBtu)	**$ 2.02**	**$ 2.35**
Cost of Gas ($/mmBtu)	**$ 3.30**	**$ 2.18**

[1] NRG's interests in Keystone and Conemaugh (jointly owned plants) are excluded from the fuel statistics schedule

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1Q 2017 Generation & Operational Performance Metrics

(MWh 000's)	2017 Generation[1]	2016 Generation[1]	MWh Change	% Change	2017 EAF[2]	2017 NCF[3]	2016 EAF[2]	2016 NCF[3]
Gulf Coast – Texas	7,720	6,566	1,155	18%	85%	34%	87%	28%
Gulf Coast – South Central	4,062	4,295	(233)	(5%)	87%	45%	91%	47%
East	5,921	8,293	(2,377)	(29%)	91%	13%	83%	16%
West	517	724	(207)	(29%)	87%	5%	76%	6%
Renewables	930	1,089	(159)	(15%)	97%	39%	97%	45%
NRG Yield[4]	2,390	2,683	(294)	(11%)	92%	18%	93%	21%
Total	**21,540**	**23,651**	**(2,115)**	**(9%)**	**89%**	**21%**	**85%**	**21%**
Gulf Coast – Texas Nuclear	2,319	2,502	(183)	(7%)	92%	91%	98%	97%
Gulf Coast – Texas Coal	5,015	3,098	1,917	62%	93%	55%	81%	34%
Gulf Coast – South Central Coal	965	420	545	130%	81%	49%	88%	21%
East Coal	4,235	6,622	(2,387)	(36%)	87%	26%	71%	31%
Baseload	**12,533**	**12,641**	**(108)**	**(1%)**	**89%**	**42%**	**77%**	**36%**
Renewables Solar	326	380	(54)	(14%)	99%	40%	100%	50%
Renewables Wind	604	710	(105)	(15%)	96%	39%	97%	44%
NRG Yield Solar	213	246	(33)	(14%)	99%	22%	100%	25%
NRG Yield Wind	1,449	1,532	(83)	(5%)	97%	33%	97%	34%
Intermittent	**2,592**	**2,868**	**(275)**	**(10%)**	**97%**	**33%**	**97%**	**36%**
East Oil	36	245	(209)	(85%)	93%	0%	96%	2%
Gulf Coast – Texas Gas	387	966	(579)	(60%)	78%	3%	89%	8%
Gulf Coast – South Central Gas	3,097	3,875	(779)	(20%)	89%	44%	91%	54%
East Gas	1,650	1,428	217	15%	93%	10%	86%	10%
West Gas	517	724	(207)	(29%)	87%	5%	76%	6%
NRG Yield Conventional	142	261	(119)	(46%)	84%	3%	87%	6%
NRG Yield Thermal[4]	585	644	(59)	(9%)	100%	3%	100%	33%
Intermediate / Peaking	**6,414**	**8,143**	**(1,733)**	**(21%)**	**88%**	**10%**	**87%**	**12%**

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes MWh (thermal heating & chilled water generation); NCF not inclusive of MWht

In the Money Availability Calculation

"In the Money Availability" (IMA) is an NRG performance measurement leveraging Generating Availability Data System (GADS) data and market prices to calculate the percentage of generation available during periods when market prices allow these units to be dispatched profitably.

- Transitioning from Equivalent Availability Factor (EAF) to IMA allows us to measure our availability during the greatest opportunities to capture value. IMA performance measurement bridges operational performance to shareholder value.
- IMA uses similar approach as GADS EAF calculation:

$$\textbf{EAF} = \frac{\text{Avail Hours} - \text{All Eq. Unplanned Outage Hrs}}{\text{Period Hours}} \times 100$$

$$\textbf{IMA} = \frac{\text{IMA Avail Hours} - \text{IMA Eq Lost Margin Hrs}}{\text{IMA Avail Hours}} \times 100$$

- Factors that impact IMA include forced outages, derates, maintenance, and/or extensions to planned and unplanned outages, when a unit is in the money; reserve shutdown (SH) hours are not included
- IMA "Available Hours" equals period hours less planned outage hours and uneconomic hours when an unplanned curtailing event occurs
- IMA "Equivalent Lost Margin Hours" (ELMH) are calculated similarly Equivalent Unplanned Outage Hours (EUOH) used for EAF
  - If there is lost margin during the hour of the curtailing event, the hour is be included as both an IMA Available Hour and an IMA ELMH
  - If there is zero lost margin during the hour of the curtailing event, the hour is not included in the available hour count AND the ELMH would be zero for that hour

PJM Capacity Clears: Merchant Wholesale Generation

PJM Region	Planning Year	Base Product: Average Price ($/MW-day)[1]	Base Product: MWs Cleared	Capacity Performance Product: Average Price ($/MW-day)[1]	Capacity Performance Product: MWs Cleared
ComEd	2017-2018	$145.51	539	$151.50	3,227
	2018-2019	$25.36	225	$215.00	3,509
	2019-2020	$182.77	65	$202.77	3,738
MAAC	2017-2018	$147.38	574	$151.50	1,753
	2018-2019	$149.98	10	$164.77	2,229
	2019-2020	$80.00	10	$100.00	2,093
EMAAC	2017-2018	$97.69	391	$151.50	204
	2018-2019	$210.63	91	$225.42	424
	2019-2020	$99.77	103	$119.77	414
DPL South	2017-2018	$150.03	133	$151.50	358
	2018-2019	$210.63	98	$225.42	459
	2019-2020	NA	NA	$119.77	481
PEPCO	2017-2018	$118.97	1,908	$151.50	2,501
	2018-2019	$149.98	58	$164.77	3,870
	2019-2020	NA	NA	$100.00	3,879
ATSI	2017-2018	$141.79	271	$151.50	647
	2018-2019	$149.98	57	$164.77	681
	2019-2020	$80.00	2	$100.00	550
RTO	2017-2018	$126.41	1,188	$151.50	449
	2018-2019	$182.04	199	$279.35	495
	2019-2020	$80.00	191	NA	NA
Net Total	2017-2018	$127.26	5,005	$151.50	9,140
	2018-2019	$136.09	738	$189.32	11,666
	2019-2020	$103.42	370	$136.03	11,154

Delivery Year Total Revenue

	NRG	GenOn	Total
17/18	$286	$452	$738
18/19	$354	$489	$843
19/20	$309	$260	$569

PJM Capacity Revenue by Calendar Year

	NRG	GenOn	Total
2017	$247	$410	$658
2018	$326	$473	$799
2019	$327	$354	$682
2020	$128	$108	$236

Assumptions:

- Data as of 3/31/2017
- Includes imports
- Excludes NRG Demand Response and Energy Efficiency
- Excludes Aurora and Rockford
- Excludes NRG Yield Assets
- 2017 Includes Jan'17 through Dec.17
- 2020 Includes Jan'20 through May'20

[1] Average Price ($/MW-day) can vary from stated BRA cleared auction price due to MWs purchased or sold in incremental auctions

PJM Capacity Clears: Merchant Wholesale Generation - GenOn

PJM Region	Planning Year	Base Product: Average Price ($/MW-day)[1]	Base Product: MWs Cleared	Capacity Performance Product: Average Price ($/MW-day)[1]	Capacity Performance Product: MWs Cleared
ComEd	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
MAAC	2017-2018	$148.27	558	$151.50	1,647
	2018-2019	$149.98	9	$164.77	2,122
	2019-2020	$80.00	9	$100.00	1,988
EMAAC	2017-2018	$97.69	391	$151.50	204
	2018-2019	$210.63	91	$225.42	424
	2019-2020	$99.77	103	$119.77	414
DPL South	2017-2018	NA	NA	NA	NA
	2018-2019	NA	NA	NA	NA
	2019-2020	NA	NA	NA	NA
PEPCO	2017-2018	$119.31	1,828	$151.50	2,501
	2018-2019	$149.98	58	$164.77	3,801
	2019-2020	NA	NA	$100.00	3,814
ATSI	2017-2018	$141.79	271	$151.50	647
	2018-2019	$149.98	57	$164.77	681
	2019-2020	$80.00	2	$100.00	550
RTO	2017-2018	$127.30	281	$151.50	440
	2018-2019	$182.04	199	$164.77	495
	2019-2020	$80.00	191	NA	NA
Net Total	2017-2018	$124.13	3,329	$151.50	5,439
	2018-2019	$178.69	414	$168.19	7,522
	2019-2020	$86.67	305	$101.21	6,766

Delivery Year Total Revenue

	GenOn	Total
17/18	$452	$452
18/19	$489	$489
19/20	$260	$260

PJM Capacity Revenue by Calendar Year

	GenOn	Total
2017	$410	$410
2018	$473	$473
2019	$354	$354
2020	$108	$108

Assumptions:

- Data as of 3/31/2017
- Includes imports
- Excludes Aurora and Rockford
- Excludes NRG Yield Assets
- 2017 Includes Jan'17 through Dec'17
- 2020 Includes Jan'20 through May'20

[1]Average Price ($/MW-day) can vary from stated BRA cleared auction price due to MWs purchased or sold in incremental auctions

PJM Asset List: Merchant Wholesale Generation

Net Generating Capacity by LDA

RTO (824 MW)

Name	Location	Capacity	Entity	Ownership %
Cheswick	Springdale, PA	565	GenOn	100.0%
Brunot Island	Pittsburgh, PA	259	GenOn	100.0%

ATSI (1,012 MW)

Name	Location	Capacity	Entity	Ownership %
Avon Lake	Avon Lake, OH	659	GenOn	100.0%
Niles	Niles, OH	25	GenOn	100.0%
New Castle	West Pittsburg, PA	328	GenOn	100.0%

COMED (4,336 MW)

Name	Location	Capacity	Entity	Ownership %
Fisk	Chicago, IL	172	NRG	100.0%
Joliet	Joliet, IL	1,326	NRG	100.0%
Powerton	Pekin, IL	1,538	NRG	100.0%
Waukegan	Waukegan, IL	790	NRG	100.0%
Will County	Romeoville, IL	510	NRG	100.0%

DPL (593 MW)

Name	Location	Capacity	Entity	Ownership %
Indian River	Millsboro, DE	426	NRG	100.0%
Vienna	Vienna, MD	167	NRG	100.0%

EMAAC (655 MW)

Name	Location	Capacity	Entity	Ownership %
Gilbert	Milford, NJ	438	GenOn	100.0%
Sayreville	Sayreville, NJ	217	GenOn	100.0%

MAAC (2,581 MW)

Name	Location	Capacity	Entity	Ownership %
Blossburg	Blossburg, PA	19	GenOn	100.0%
Conemaugh	New Florence, PA	282	GenOn	16.45%
Conemaugh	New Florence, PA	63	NRG	3.75%
Hamilton	East Berlin, PA	20	GenOn	100.0%
Hunterstown CCGT	Gettysburg, PA	810	GenOn	100.0%
Keystone	Shelocta, PA	63	NRG	3.70%
Keystone	Shelocta, PA	285	GenOn	16.67%
Mountain	Mount Holly Springs, PA	40	GenOn	100.0%
Orrtanna	Orrtanna, PA	20	GenOn	100.0%
Portland	Portland, PA	169	GenOn	100.0%
Shawnee	East Stoudsburg, PA	20	GenOn	100.0%
Shawville	Shawville, PA	603	GenOn	100.0%
Titus	Birdsboro, PA	31	GenOn	100.0%
Tolna	Stewartstown, PA	39	GenOn	100.0%
Warren	Warren, PA	57	GenOn	100.0%
Hunterstown CTs	Gettysburg, PA	60	GenOn	100.0%

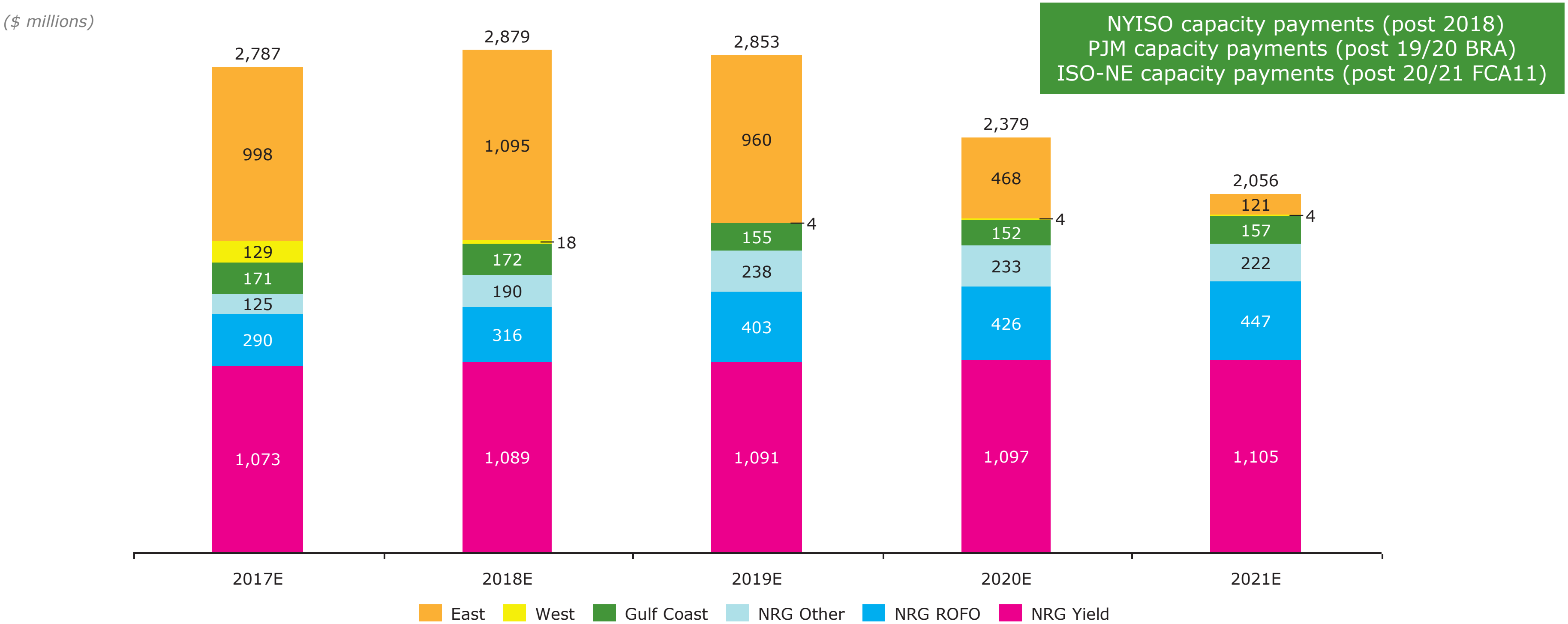
PEPCO (4,683 MW)

Name	Location	Capacity	Entity	Ownership %
Chalk Point	Prince Georges County, MD	2,279	GenOn	100.0%
Dickerson	Montgomery County, MD	849	GenOn	100.0%
Morgantown	Charles County, MD	1,477	GenOn	100.0%
SMECO	Prince Georges County, MD	78	NRG	100.0%

Assumptions:
- Data reflects physical location of generating unit; reflects nameplate capacity, including conversions
- Excludes NYLD assets Dover 104 MW in DPL and Paxton Creek 12 MW in MAAC
- Data as of 3/31/2017

Appendix: Finance

Fixed Contracted and Capacity Revenue (Q1-2017)



Notes:

- East includes cleared capacity auction for PJM through May 2020, New England ISO Forward Capacity Auction 11(FCA11) through May 2021; NY on rolling forward basis
- West includes committed Resource Adequacy contracts & tolling agreements
- Gulf Coast region includes South Central capacity sold into PJM/MISO auctions and Co-Op contracted revenues. Co-Op contracted revenues are also incorporated in the hedge table
- NRG ROFO includes all wind, solar and conventional assets which are part of ROFO agreement, including projects under construction (Carlsbad and Puente)
- NRG Other includes renewable assets which are not part of ROFO and preferred resources projects
- NRG Yield includes contracted capacity, contracted energy and contracted steam revenues

1Q2017 Net Capital Expenditures

($ millions)	Maintenance	Environmental	Growth	Total
Generation				
Gulf Coast[1]	$40	1	1	$42
East	19	24	15	58
West	-	-	81	81
Other	1	-	-	1
Retail	6	-	4	10
Renewables	1	-	67	68
NRG Yield	4	-	-	4
Corporate	1	-	3	4
Total Cash Capital Expenditures	**$72**	**$25**	**$171**	**$268**
Other Investments[2]	-	-	33	33
Project Funding, net of fees[3]	-	-	(51)	(51)
Total Capital Expenditures and Growth Investments, net	**$72**	**$25**	**$153**	**$250**

[1] Excludes $18 MM of insurance proceeds on maintenance capex; [2] Includes investments and acquisitions; [3] Includes net debt proceeds, cash grants and third-party contributions

Growth Investments and Capex, Net of Financing

($ millions)		2016A	2017E	2018E
NRG Level	Growth	564[2]	185	155
	Environmental	240	35	1
	Maintenance	220	188	215
GenOn	Growth Investments and Conversions	105	6	4
	Environmental	45	15	2
	Maintenance	118	70	93
Other[1]	Growth	3	2	-
	Environmental	-	-	-
	Maintenance	29	35	27
	Total:	**$1,324**	**$536**	**$497**

[1] Other includes NYLD, Ivanpah, and Agua Caliente; [2] Excludes contributions to nuclear decommissioning trust ($41 MM)

Generation Organizational Structure

NRG Energy, Inc. (45,909[1] MW)

Renewables (1,120 MW)

Solar
- Agua Caliente[5]
- Community Solar
- Distributed Solar
- Guam
- Ivanpah
- Spanish Town

Wind
- Bingham Lake
- Broken Bow
- Cedro Hill
- Community Wind
- Crofton Bluffs
- Eastridge
- Jeffers
- Langford
- Mountain Wind I&II
- Sherbino
- Westridge

NRG Yield (2,756 MW)

- Alta Wind
- Alpine
- Avenal
- Avra Valley
- Blythe
- Borrego
- Buffalo Bear
- Crosswinds
- CVSR
- Desert Sunlight
- Distributed Solar
- Dover
- El Segundo
- Elbow Creek
- Elkhorn Ridge
- Forward
- GenConn Devon
- GenConn Middletown
- Goat Wind
- Hardin
- High Desert
- Kansas South
- Laredo Ridge
- Lookout
- Marsh Landing
- Odin
- Paxton Creek
- Pinnacle
- Princeton
- Roadrunner
- San Juan Mesa
- South Trent
- Spanish Fork
- Spring Canyon II & III
- Sleeping Bear
- Taloga
- Tucson
- Univ. of Bridgeport
- Walnut Creek
- Wildorado

Gulf Coast (14,863 MW)

- Bayou Cove
- Big Cajun I[4]
- Big Cajun II
- Cedar Bayou
- Cedar Bayou[3]
- Choctaw[4]
- Cottonwood
- Greens Bayou
- Gregory
- Limestone
- San Jacinto
- South Texas Project
- Sterlington[4]
- TH Wharton
- WA Parish

Other Conventional (22 MW)

- Petra Nova Cogen

Drop down to NRG Yield on March 27, 2017:
- Agua Caliente[5]
- Four Brothers[6]
- Granite Mountain[6]
- Iron Springs[6]

West (4,899 MW)

- Ellwood
- Encina
- Etiwanda
- Long Beach
- Mandalay
- Midway Sunset
- Ormond Beach
- Saguaro
- San Diego Jet
- Sunrise
- Watson

Residential Solar (114 MW)

Other (749 MW)

- Doga
- Gladstone

East (21,386 MW)

- Arthur Kill
- Astoria
- Avon Lake
- Brunot Island
- Cheswick
- Conemaugh[2]
- Connecticut Jets
- Devon
- Fisk
- Hunterstown CC
- Huntley
- Indian River
- Joliet
- Keystone[2]
- Middletown
- Montville
- New Castle
- Niles
- Oswego
- Powerton
- Vienna
- Waukegan
- Will County

GenOn Americas Generation (6,878 MW)

- Bowline
- Canal
- Martha's Vineyard

GenOn Mid-Atlantic (4,605 MW)

- Chalk Point
- Dickerson
- Morgantown

REMA (2,300 MW)

- Blossburg
- Gilbert
- Hamilton
- Hunterstown CT
- Mountain
- Orrtana
- Portland
- Sayreville
- Shawnee
- Shawville
- Titus
- Tolna
- Warren

Part of GenOn Energy, Inc. Intercompany Revolver first lien package and subject to covenants of GenOn Unsecured Notes

LEGEND

- Separate Credit Facility
- drop down to NRG Yield on March 27, 2017
- Equity Investments

[1] Capacity controlled by NRG as of 03/31/2017; [2] NRG and GenOn jointly own/lease portions of these plants; GenOn portion is subject to REMA liens; [3] Included as part of Peaker Finance Co; [4] Includes 275 MW related to Choctaw Unit 1 which is in forced outage and is expected to return to service in December 2017; [5] Agua Caliente is 51% owned by NRG Consolidated, of which 16% is owned by NRG Yield; [6] Four Brothers, Granite Mountain, and Iron Springs are 50% owned by NRG Yield

Consolidated Debt Structure

($ millions)
As of 03/31/2017

LEGEND
- Recourse Debt
- Non-Recourse Debt
- SEC Filer

NRG Energy, Inc.

Revolver $2.5 BN due 2018/2021[1]	$	125
Senior notes due 2018-2027		5,449
Term loan due 2023		1,886
Tax exempt bonds due 2038-2045		455
Capital Lease		8
Total	**$**	**7,923**

GenOn Energy, Inc.

Unsecured notes due 2017-2020	$ 1,830
GenOn Hunterstown WG LP	54
GenOn Choctaw	41
Secured revolver from NRG Energy, Inc. (Intercompany)[2]	125

REMA

Capital lease	$	2
Operating leases[3]		–

GenOn Americas Generation

Senior unsecured notes due 2021 & 2031	$	695

GenOn Mid-Atlantic

Capital lease	$	–
Operating leases[3]		–

Conventional Financings

Other non-recourse debt	7

Midwest Generation

Capacity Monetization/ Operating leases[4]	$	213

Agua Caliente

Project financing due 2037	$	846
Borrower1 due 2038		89

Ivanpah

Promissory Note and Project financing due 2033 and 2038	1,179

Other Renewables Financings

Project financings	$	545
Capital Lease		2

NRG Yield, Inc.

Senior convertible notes due 2019-2020	$	633

NRG Yield Operating LLC

Revolver $495 MM due 2019[5]	$	0
Green Bond notes		500
Senior Notes Due 2026		350

Conventional

Term loans due 2017 & 2023	$	1,124

Thermal

Senior secured notes due 2017-2025 and 2031	$	219

Renewable

Project financings[6]	$ 3,225

Note: Debt balances exclude discounts and premiums
[1] $1,172 MM LC's issued and $1,364 MM Revolver available at NRG
[2] $125 MM cash draw to support LCs on the Morgantown (GENMA) operating leases. $161 MM of LC's were issued ($68 MM on behalf of GAG) with $214 MM of the Intercompany Revolver remaining as available – see 1st quarter 2017 10Q for further details
[3] The present value of lease payments (10% discount rate) for GenOn Mid-Atlantic operating lease is $583 MM, and the present value of lease payments (9.4% discount rate) for REMA operating lease is $346 MM
[4] The present value of lease payments (9.1% discount rate) for Midwest Generation operating lease is $88 MM; this lease is guaranteed by NRG Energy, Inc.
[5] $64 MM of LC's were issued and $431 MM of the Revolver was available at NYLD
[6] Includes Four Brothers Holdings, Iron Springs Renewables, and Granite Mountain Renewables following the drop down on 03/27/2017

Recourse / Non-Recourse Debt

($ millions)	03/31/2017	12/31/2016	09/30/2016	06/30/2016
Recourse Debt				
Term Loan Facility	$ 1,886	$ 1,891	$ 1,895	$ 1,900
Senior Notes	5,449	5,449	5,827	5,889
Tax Exempt Bonds	455	455	455	455
Revolver	125	-	-	-
Capital Lease	8	-	-	-
Recourse Debt Subtotal	**$ 7,923**	**$ 7,795**	**$ 8,177**	**$ 8,244**
Non-Recourse Debt				
Total NRG Yield[1,2]	$ 6,051	$ 6,085	$ 5,733	$ 5,583
GenOn Senior Notes	1,830	1,830	1,830	1,830
GenOn Americas Generation Notes	695	695	695	695
GenOn Other (including capital leases) [3]	97	98	54	55
Renewables (including capital leases)[2]	2,661	2,592	2,586	2,487
Conventional	220	238	257	277
Non-Recourse Debt and Capital Lease Subtotal	**$ 11,554**	**$ 11,538**	**$ 11,155**	**$ 10,927**
Total Debt	**$ 19,477**	**$ 19,333**	**$ 19,332**	**$ 19,171**

Note: Debt balances exclude discounts and premiums
[1] Includes convertible notes and project financings, including $179 MM related to Viento - NRG owns 25% of the project; [2] NRG Yield has been recast following the CVSR drop down on 09/01/2016 and the Four Brothers, Iron Springs, and Granite Mountain drop down on 03/27/2017; [3] Excludes GenOn's intercompany revolver balance of $125 MM

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GenOn: Organizational Structure

($ millions)
MWs and Balances as of 03.31.17

Subject to restricted payments

GenOn Energy, Inc. (15,394 MW)	
7.875% Unsecured Notes, due 2017	$691
9.500% Unsecured Notes, due 2018	$649
9.875% Unsecured Notes, due 2020	$490
Secured Revolver from NRG Energy, Inc. (Intercompany)[1]	$125
Total Debt[2]	**$1,955**
Consolidated Cash Balance	**$885**

GenOn Energy Holdings

REMA (2,300 MW)	
Capital Leases	$2
Operating Leases[4]	$342
Consolidated Cash Balance	**$82**

Asset	MW	ISO	Asset	MW	ISO
Blossburg	19	PJM	Portland	169	PJM
Conemaugh[3]	282	PJM	Sayreville	217	PJM
Gilbert	438	PJM	Shawnee	20	PJM
Hamilton	20	PJM	Shawville	603	PJM
Hunterstown CT	60	PJM	Titus	31	PJM
Keystone[3]	285	PJM	Tolna	39	PJM
Mountain	40	PJM	Warren	57	PJM
Orrtanna	20	PJM			

GenOn Americas Generation (6,878 MW) (formerly "MAGI")	
8.500% Senior Unsecured Notes, due 2021	$366
9.125% Senior Unsecured Notes, due 2031	$329
Total Debt[5]	**$695**
Consolidated Cash Balance (includes "MIRMA")	**$305**

GenOn Mid-Atlantic (4,605 MW) ("MIRMA")	
Operating Leases[4]	$597
Consolidated Cash Balance	**$305**

Asset	MW	ISO
Chalk Point	2,279	PJM
Dickerson	849	PJM
Morgantown	1,477	PJM

Rest of GenOn Americas (2,273 MW)
No Debt

Asset	MW	ISO
Bowline	1,147	NYISO
Canal Units 1-2	1,112	ISONE
Martha's Vineyard	14	ISONE

Rest of GenOn Inc (6,216 MW)	
Vendor Financing (Hunterstown)	$54
Vendor Financing (Choctaw)[6]	$41

Asset	MW	ISO	Asset	MW	ISO
Avon Lake	659	PJM	Hunterstown CCGT	810	PJM
Brunot Island	259	PJM	Mandalay	560	CAISO
Cheswick	565	PJM	New Castle	328	PJM
Choctaw [6]	800	SERC	Niles	25	PJM
Ellwood	54	CAISO	Ormond Beach	1,516	CAISO
Etiwanda	640	CAISO			

[1] $125 MM cash draw to support LCs on the Morgantown (GENMA) operating leases – see 1st quarter 2017 10Q for further details; [2] Excludes premium of $69 MM on GenOn debt; [3] REMA jointly leases portions of these plants; GenOn portion is subject to REMA liens; [4] The present value of the lease payments (10% discount rate at GenMA; 9.4% at REMA); [5] Excludes premiums of $48 MM; [6] Includes 275 MW related to Choctaw Unit 1 which is in forced outage and is expected to return to service in December 2017

Schedule of Debt Maturities

$ in millions as of March 31, 2017				
		NRG	Nonrecourse to NRG	
Issuance	**Maturity Year**	**Recourse**	**GenOn**	**Yield**
7.875% GenOn Senior Notes	**2017**	$ -	**$ 691**	$ -
7.625% NRG Senior Notes	2018	398	-	-
9.50% GenOn Senior Notes	2018	-	649	-
	2018 Total	**398**	**649**	**-**
3.5% NRG Yield, Inc. Convertible Notes	**2019**	**-**	**-**	**345**
9.875% GenOn Senior Notes	2020	-	490	-
3.25% NRG Yield, Inc. Convertible Notes	2020	-	-	288
	2020 Total	**-**	**490**	**288**
7.875% NRG Senior Notes	2021	207	-	-
8.50% GenOn Americas Generation Senior Notes	2021	-	366	-
	2021 Total	**207**	**366**	**-**
4.750% Tax Exempt Bonds due 2022	2022	54	-	-
6.25% NRG Senior Notes	2022	992	-	-
	2022 Total	**1,046**	**-**	**-**
NRG Term Loan	2023	1,886		
Revolver	2023	125		
6.625% NRG Senior Notes	2023	869	-	-
	2023 Total	**2,880**	**-**	**-**
6.25% NRG Senior Notes	2024	733	-	-
5.375% Yield Operating LLC Senior Notes	2024	-		500
	2024 Total	**733**	**-**	**500**
7.25% NRG Senior Notes	2026	1,000	-	-
5% NRG Yield Operating LLC Senior Notes	2026	-	-	350
	2026 Total	**1,000**	**-**	**350**
6.625% NRG Senior Notes	**2027**	**1,250**	**-**	
9.125% GenOn Americas Generation Senior Notes	**2031**	**-**	**329**	**-**
6.0% Tax Exempt Bonds	**2040**	**57**	**-**	**-**
4.750% Tax Exempt Bonds	2042	22	-	-
4.750% Tax Exempt Bonds	2042	73	-	-
5.875% Tax Exempt Bonds	2042	59	-	-
	2042 Total	**154**	**-**	**-**
5.375% Tax Exempt Bonds	**2045**	**190**	**-**	**-**
	Subtotal	**7,915**	**2,525**	**1,483**
Non-Recourse Project Debt and Capital Leases[1]	**Various**	**8**	**97**	**4,568**
	Total Debt		**$ 2,622**	**$ 6,051**

Note: Debt balances exclude discounts and premiums

[1] Includes project-level debt and capital leases that are non-recourse to NRG, GenOn and NRG Yield

Appendix:
Reg. G Schedules

Reg. G: 1Q17 Free Cash Flow before Growth

($ millions)		03/31/2017
Adjusted EBITDAR	**$**	**445**
Less: GenOn & EME operating lease expense		(33)
Adjusted EBITDA	**$**	**412**
Interest payments		(228)
Income tax		1
Collateral / working capital / other		(253)
Cash Flow from Operations	**$**	**(68)**
Reclassifying of net receipts (payments) for settlement of acquired derivatives that include financing elements		1
Land Sale		8
Return of capital from equity investments[1]		14
Collateral		74
Adjusted Cash Flow from Operations	**$**	**29**
Maintenance capital expenditures, net [2]		(54)
Environmental capital expenditures, net		(25)
Distributions to non-controlling interests		(46)
Consolidated Free Cash Flow before Growth	**$**	**(96)**
Less: FCFbG at Non-Guarantor Subsidiaries[3]		(47)
NRG-Level Free Cash Flow before Growth	**$**	**(49)**

[1] Represents cash distributions to NRG from equity investments; [2] Includes insurance proceeds of $18 MM; [3] Reflects impact from GenOn, NRG Yield, and other excluded project subsidiaries

Reg. G: 2017 Guidance

Appendix Table A-1: 2017 Guidance

The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	**2017 Guidance**
Generation and Renewables	$1,080 - $1,200
Retail Mass	700 – 780
NRG Yield	920
Adjusted EBITDA	**$2,700 - $2,900**
Interest payments	(1,065)
Income tax	(40)
Working capital / other	(240)
Adjusted Cash Flow from Operations	**$1,355 - $1,555**
Maintenance capital expenditures, net	(280) - (310)
Environmental capital expenditures, net	(40) - (60)
Distributions to non-controlling interests[1]	(185) – (205)
Consolidated Free Cash Flow before Growth	**$800 - $1,000**
Less: FCFbG at Non-Guarantor Subsidiaries[2]	(100)
NRG-Level Free Cash Flow before Growth	**$700 - $900**

[1] Includes NRG Yield distributions to public shareholders, and Capistrano and Solar distributions to non-controlling interests; [2] Reflects impact from GenOn, NRG Yield, and other excluded project subsidiaries

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Appendix Table A-2: First Quarter 2017 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (loss)/income	**67**	**(33)**	**(31)**	**(1)**	**(205)**	**(203)**
Plus:						
Interest expense, net	20	1	21	76	147	265
Income tax	-	3	(6)	(1)	-	(4)
Loss on debt extinguishment	-	-	2	-	-	2
Depreciation and amortization	138	28	49	75	10	300
ARO Expense	13	-	-	1	-	14
Amortization of contracts	(5)	1	-	17	-	13
Amortization of leases	(12)	-	-	-	-	(12)
EBITDA	**221**	**-**	**35**	**167**	**(48)**	**375**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	13	(3)	(4)	13	-	19
Acquisition-related transaction & integration costs	-	-	-	1	-	1
Reorganization costs	-	-	-	-	8	8
Deactivation costs	3	-	-	-	1	4
Other non recurring charges	(1)	(1)	-	3	(2)	(1)
Mark to market (MtM) (gains)/losses on economic hedges	(125)	137	(6)	-	-	6
Adjusted EBITDA	**111**	**133**	**25**	**184**	**(41)**	**412**

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Appendix Table A-3: First Quarter 2016 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Generation	Retail	Renewables	NRG Yield	Corp/Elim	Total
Net (Loss)/Income	**191**	**150**	**(40)**	**2**	**(256)**	**47**
Plus:						
Interest expense, net	10	-	27	74	170	281
Income tax	-	-	(6)	-	27	21
Gain on debt extinguishment	-	-	-	-	(11)	(11)
Depreciation and amortization	144	30	48	74	17	313
ARO Expense	9	-	-	1	-	10
Amortization of contracts	(2)	3	-	23	(3)	21
Amortization of leases	(12)	-	-	-	-	(12)
EBITDA	**340**	**183**	**29**	**174**	**(56)**	**670**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	9	-	-	24	1	34
Reorganization costs	1	5	2	-	2	10
Deactivation costs	7	-	-	-	-	7
Gain on sale of business	(29)	-	-	-	-	(29)
Other non recurring charges	2	1	3	-	3	9
Impairments	137	-	-	-	9	146
MtM (gains)/losses on economic hedges	(1)	(33)	(1)	-	-	(35)
Adjusted EBITDA	**466**	**156**	**33**	**198**	**(41)**	**812**

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Appendix Table A-4: First Quarter 2017 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Gulf Coast	East	West	Other	Total
Net (loss)/income	**39**	**36**	**(7)**	**(1)**	**67**
Plus:					
Interest expense, net	1	19	-	-	20
Depreciation and amortization	73	59	6	-	138
ARO expense	4	6	3	-	13
Amortization of contracts	2	(5)	(2)	-	(5)
Amortization of leases	-	(12)	-	-	(12)
EBITDA	**119**	**103**	**-**	**(1)**	**220**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	7		3	3	13
Deactivation costs	-	1	2	-	3
Other non recurring charges	-	(2)	1	-	(1)
Mark-to- Market (MtM) losses on economic hedges	(121)	3	(7)	-	(125)
Adjusted EBITDA	**5**	**105**	**(1)**	**3**	**111**

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Appendix Table A-5: First Quarter 2016 Regional Adjusted EBITDA Reconciliation for Generation
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	**Gulf Coast**	**East**	**West**	**Other**	**Total**
Net loss	**(125)**	**242**	**30**	**44**	**191**
Plus:					
Interest expense, net	-	10	-	-	10
Depreciation and amortization	76	53	15	-	144
ARO expense	3	4	2	-	9
Amortization of contracts	2	(5)	1	-	(2)
Amortization of leases	(1)	(11)	-	-	(12)
EBITDA	**(45)**	**293**	**48**	**44**	**340**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	3	-	2	4	9
Reorganization costs	1	-	-	-	1
Deactivation costs	-	7	-	-	7
Gain on sale of assets	-	(29)	-	-	(29)
Other non recurring charges	-	-	-	2	2
Impairments	137	-	-	-	137
MtM (gains)/losses on economic hedges	26	(30)	3	-	(1)
Adjusted EBITDA	**122**	**241**	**53**	**50**	**466**

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Appendix Table A-6: Expected Full Year 2017 Free Cash Flow before Growth Reconciliation for GenOn Energy, Inc., and NRG Yield (NYLD) / Other[1]: The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	2017 FY		
	Genon	**NYLD /Other**	**Total**
Adjusted EBITDA	**130**	**1,265**	**1,395**
Interest payments	(240)	(350)	(590)
Collateral / working capital / other	(125)	(143)	(268)
Cash Flow from Operations	**(235)**	**772**	**537**
Maintenance capital expenditures, net	(70)	(35)	(105)
Environmental capital expenditures, net	(15)	-	(15)
Distributions to NRG	-	(142)	(142)
Distributions to non-controlling interests	-	(175)	(175)
Free Cash Flow before Growth	**(320)**	**420**	**100**

[1] Includes NRG Yield and other assets (primarily Aqua Caliente, Ivanpah, and Capistrano)

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Appendix Table A-7: 2017 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to net income:

	2017 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**
GAAP Net Income [1]	60	260
Income tax	80	80
Interest Expense and Debt Extinguishment Costs	1,155	1,155
Depreciation, Amortization, Contract Amortization and ARO Expense	1,235	1,235
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	110	110
Other Costs [2]	60	60
Adjusted EBITDA	**2,700**	**2,900**

[1] For purposes of guidance, fair value accounting related to derivatives are assumed to be zero.
[2] Includes deactivation costs, gain on sale of businesses, asset write-offs, impairments and EVgo Califonia settlement

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Appendix Table A-8: Expected Full Year 2017 Adjusted EBITDA Reconciliation for GenOn Energy, Inc., ROFO/ Other[1,2], and NRG Yield[2]

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to net (loss)/income

($ millions)	Genon	ROFO/Other	NRG Yield
Net (loss)/income	**(161)**	**53**	**140**
Plus:			
Income tax	-	(5)	25
Interest expense, net	186	88	290
Depreciation, Amortization, Contract Amortization, and ARO Expense	133	198	381
EBITDA	**158**	**334**	**836**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	-	(10)	80
Deactivation costs	22	-	-
Other non-recurring charges	-	-	4
Mark to market (MtM) losses on economic hedges	(50)	21	-
Plus: Operating lease expense	112	21	-
Adjusted EBITDAR	**242**	**366**	**920**
Less: Operating lease expense	(112)	(21)	-
Adjusted EBITDA	**130**	**345**	**920**

[1] Includes Aqua Caliente, Ivanpah, Midwest Generation, Capistrano, and other assets; [2] In accordance with GAAP, restated to reflect impact of Utah Solar and NRG's 31% interest in Agua Caliente drop down to NRG Yield

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EBITDA and Adjusted EBITDA are non-GAAP financial measures. These measurements are not recognized in accordance with GAAP and should not be viewed as an alternative to GAAP measures of performance. The presentation of Adjusted EBITDA should not be construed as an inference that NRG's future results will be unaffected by unusual or non-recurring items.

EBITDA represents net income before interest (including loss on debt extinguishment), taxes, depreciation and amortization. EBITDA is presented because NRG considers it an important supplemental measure of its performance and believes debt-holders frequently use EBITDA to analyze operating performance and debt service capacity. EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our operating results as reported under GAAP. Some of these limitations are:

EBITDA does not reflect cash expenditures, or future requirements for capital expenditures, or contractual commitments;

EBITDA does not reflect changes in, or cash requirements for, working capital needs;

EBITDA does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on debt or cash income tax payments;

Although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements; and

Other companies in this industry may calculate EBITDA differently than NRG does, limiting its usefulness as a comparative measure.

Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to use to invest in the growth of NRG's business. NRG compensates for these limitations by relying primarily on our GAAP results and using EBITDA and Adjusted EBITDA only supplementally. See the statements of cash flow included in the financial statements that are a part of this news release.

Adjusted EBITDA is presented as a further supplemental measure of operating performance. As NRG defines it, Adjusted EBITDA represents EBITDA excluding impairment losses, gains or losses on sales, dispositions or retirements of assets, any mark-to-market gains or losses from accounting for derivatives, adjustments to exclude the Adjusted EBITDA related to the non-controlling interest, gains or losses on the repurchase, modification or extinguishment of debt, the impact of restructuring and any extraordinary, unusual or non-recurring items plus adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. The reader is encouraged to evaluate each adjustment and the reasons NRG considers it appropriate for supplemental analysis. As an analytical tool, Adjusted EBITDA is subject to all of the limitations applicable to EBITDA. In addition, in evaluating Adjusted EBITDA, the reader should be aware that in the future NRG may incur expenses similar to the adjustments in this news release.

Management believes Adjusted EBITDA is useful to investors and other users of NRG's financial statements in evaluating its operating performance because it provides an additional tool to compare business performance across companies and across periods and adjusts for items that we do not consider indicative of NRG's future operating performance. This measure is widely used by debt-holders to analyze operating performance and debt service capacity and by equity investors to measure our operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. Management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations, and for evaluating actual results against such expectations, and in communications with NRG's Board of Directors, shareholders, creditors, analysts and investors concerning its financial performance.

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Adjusted cash flow from operating activities is a non-GAAP measure NRG provides to show cash from operations with the reclassification of net payments of derivative contracts acquired in business combinations from financing to operating cash flow, as well as the add back of merger, integration and related restructuring costs. The Company provides the reader with this alternative view of operating cash flow because the cash settlement of these derivative contracts materially impact operating revenues and cost of sales, while GAAP requires NRG to treat them as if there was a financing activity associated with the contracts as of the acquisition dates. The Company adds back merger, integration related restructuring costs as they are one time and unique in nature and do not reflect ongoing cash from operations and they are fully disclosed to investors.

Free cash flow (before Growth investments) is adjusted cash flow from operations less maintenance and environmental capital expenditures, net of funding, preferred stock dividends and distributions to non-controlling interests and is used by NRG predominantly as a forecasting tool to estimate cash available for debt reduction and other capital allocation alternatives. The reader is encouraged to evaluate each of these adjustments and the reasons NRG considers them appropriate for supplemental analysis. Because we have mandatory debt service requirements (and other non-discretionary expenditures) investors should not rely on free cash flow before Growth investments as a measure of cash available for discretionary expenditures.

Free Cash Flow before Growth Investment is utilized by Management in making decisions regarding the allocation of capital. Free Cash Flow before Growth Investment is presented because the Company believes it is a useful tool for assessing the financial performance in the current period. In addition, NRG’s peers evaluate cash available for allocation in a similar manner and accordingly, it is a meaningful indicator for investors to benchmark NRG's performance against its peers. Free Cash Flow before Growth Investment is a performance measure and is not intended to represent net income (loss), cash from operations (the most directly comparable U.S. GAAP measure), or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.