NRG Energy Inc.

Second Quarter 2019 Earnings Presentation

August 7, 2019

Safe Harbor

Forward-Looking Statements

In addition to historical information, the information presented in this presentation 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 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, general economic conditions, hazards customary in the power industry, weather 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, changes in government regulations, the condition of capital markets generally, our ability to access capital markets, cyberterrorism and inadequate cybersecurity, 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 implement and execute on our publicly announced transformation plan, including any cost savings and margin enhancement, our ability to achieve our net debt targets, our ability to achieve investment grade credit metrics, our ability to proceed with projects under development or the inability to complete the construction of such projects on schedule or within budget, the inability to maintain or create successful partnering relationships, our ability to operate our businesses efficiently, our ability to retain retail customers, our ability to realize value through our commercial operations strategy, 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, and our ability to execute our Capital Allocation Plan. Achieving investment grade credit metrics is not a indication of or guarantee that the Company will receive investment grade credit ratings. 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, free cash flow guidance and excess cash guidance are estimates as of August 7, 2019. 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 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 Review

Kirk Andrews, EVP and CFO

Closing Remarks

Mauricio Gutierrez, President and CEO

Q&A

Key Messages

Platform Delivers Predictable Results; Reaffirming Guidance

**Perfecting Integrated Platform through
Stream Energy Acquisition and Solar PPAs**

**Achieved Investment Grade Metrics;
Announcing Incremental $250 MM Share Repurchase Program**

Q2 Results and Highlights

Results and Highlights

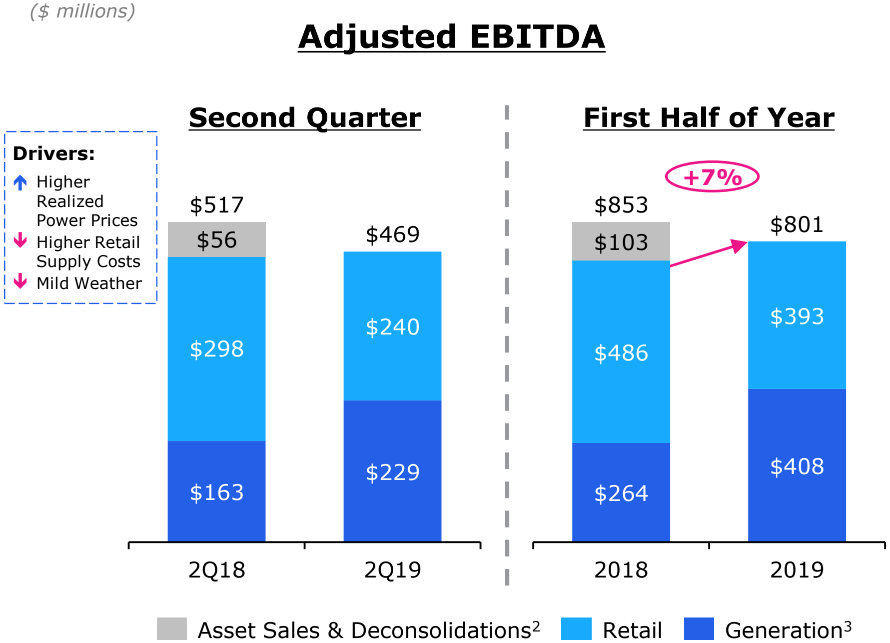
☑ **Deliver on Financial and Operational Objectives**
- ☑ Top decile safety performance
- ☑ Strong financial and operational results
- ☑ Transformation Plan cost savings and margin enhancement on track

☑ **Perfecting Integrated Platform**
- ☑ Signed 1.3 GW of solar PPAs; ~10 year avg. tenure
- ☑ Closed on acquisition of Stream Energy, August 1st

☑ **Disciplined Capital Allocation**
- ☑ Achieved 2019 investment grade metrics[1]
- ☑ Completed $1 Bn share purchase program; ending share count 253 MM
- ☑ Announcing incremental $250 MM share repurchase program to be executed by year-end
- ☐ ~$250 MM excess capital / Petra Nova reserve

Matched Portfolio Provided Stable Results

($ millions)



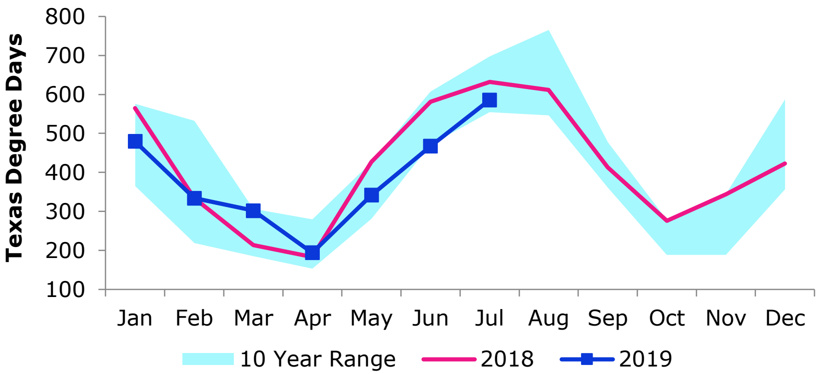
Reaffirming 2019 Guidance

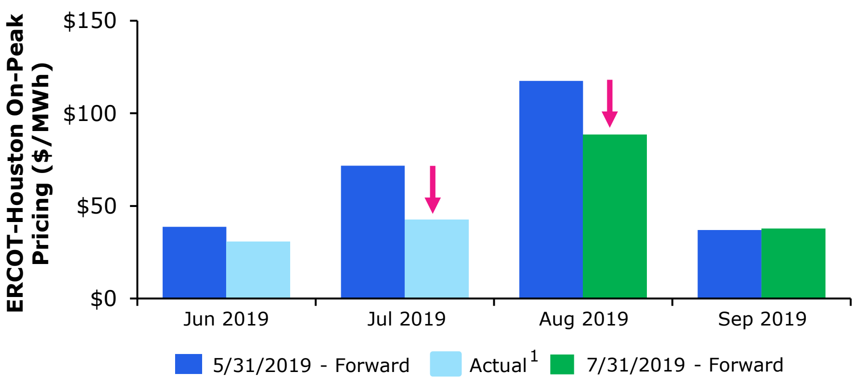
Strong Financial and Operational Execution Provides Significant Financial Flexibility to Perfect Our Customer-Focused Platform and Return Capital to Shareholders

[1] On a pro forma basis; see slide 11; [2] See slide 31; [3] Includes Corporate segment

Summer ERCOT Update

Mild Weather Impacting Power Prices





Platform Well-Positioned Through Summer

- **Integrated Platform Well-Positioned** for varying summer conditions
  - Maintaining balanced hedging program to increase earnings predictability
  - Positioned to acquire customers at-value
- **Retail Prepared** for summer volatility
  - Fully hedged on priced load
  - Enhanced customer outreach
  - Expanded Demand Management programs
- **Generation Strengthened** ahead of summer
  - Gregory, 385 MW CCGT, returned to service prior to summer
  - Expanded spring outage plan
  - Maintaining sufficient excess generation

**Platform Performs Through Volatile Summer;
Focused on Fleet Reliability and Platform Performance**

[1] Real time prices

Market Outlook - ERCOT

ERCOT Requires Significant New Build to Maintain Grid Reliability

(Nameplate Capacity; Cumulative GWs)[1]	**2020**	**2021**	**2022**
May '19 Capacity, Demand and Reserve (CDR) Report			
Peak Load Forecast	76.8	78.8	80.6
Solar	3.1	6.7	7.1
Wind	7.5	13.4	14.0
Thermal	0.3	2.0	2.0
Retirements	--	--	--
Reserve Margin	10%	15%	13%
Implied Renewable New Build to Maintain Reliability			
Solar	4-6	7-9	10-12
Wind[2]	2.5	5.0	7.5
Thermal, net of 1.7 GW at-risk[3]	0.3	0.3	0.3
Retirements, announced[4]	0.0	(1.0)	(1.4)
Reserve Margin	10-12%	10-12%	10-12%

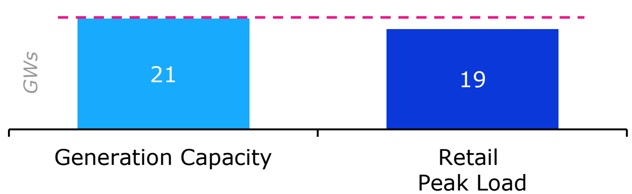
Fundamentals Trending to Remain Tight for the Foreseeable Future

- Requires over 17 GW of renewable new build over the next 3 years to maintain 10% reserve margins
- CDR report historically overstates new build and understates retirements
- Declining forward power prices do not support merchant new build and increases risk of retirements
- Likelihood of success: high for contracted renewables and low for merchant renewables and conventional

ERCOT Fundamentals Remain Tight Leading to Volatile Market Conditions

[1] Reminder: nameplate MWs are translated to reserve margin using the following factors: solar 74%, non-coastal wind 15%, coastal wind 58% of nameplate capacity; [2] Assumes 20% coastal and 80% non-coastal; [3] At-risk generation includes FGE Texas (743 MW, July 2016 original COD), Halyard Henderson (484 MW, June 2016 original COD), and Halyard Wharton (484 MW, June 2016 Original COD); all delayed multiple times; [4] Announced retirements include Oklaunion (650 MW, fall 2020 announced retirement) and Decker Creek (735 MW, Unit 1 fall 2020 and Unit 2 fall 2021 announced retirements)

Platform Designed for Stability

	2020 Balanced & Flexible		2020 Focus
1 Balanced Integrated Platform	**Minimized Market Exposure** 	✓	Continue Perfecting Integrated Model
2 Strengthened Balance Sheet	**2.5x** **Net Debt/EBITDA Achieved Investment Grade Metrics[1]**	✓	Seeking Investment Grade Credit Rating
3 Disciplined Capital Allocation	**~100%** **Free Cash Flow before Growth Available for Allocation**	✓	Continue Disciplined Capital Allocation

Increasing Stability by Better Balancing Integrated Platform and Adhering to Disciplined Capital Allocation

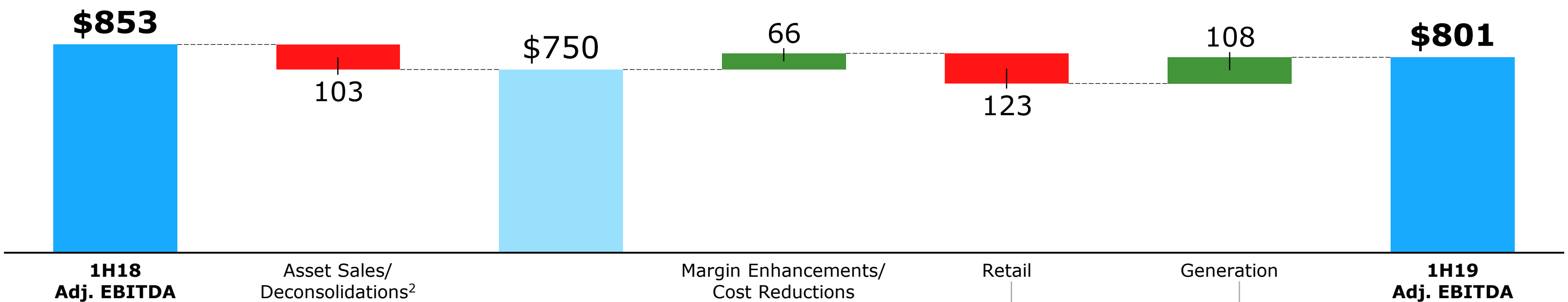
[1] On a pro forma basis; see slide 11

Financial Review

Financial Summary

($ millions)

	6/30/2019		
	Three Months Ended	**Six Months Ended**	**Reaffirming Full Year Guidance**
Retail	$240	$393	$1,000 – $1,100
Generation[1]	229	408	850 – 950
Adjusted EBITDA	**$469**	**$801**	**$1,850 - $2,050**
Consolidated Free Cash Flow before Growth ("FCFbG")	**$230**	**$204**	**$1,250 - $1,450**



Retail	
Gross Margin	($100)
Weather	(35)
XOOM	12

Generation	
Gross Margin	$127
MWG asbestos	27
ERCOT pre-summer maintenance	(21)
Other[3]	(25)

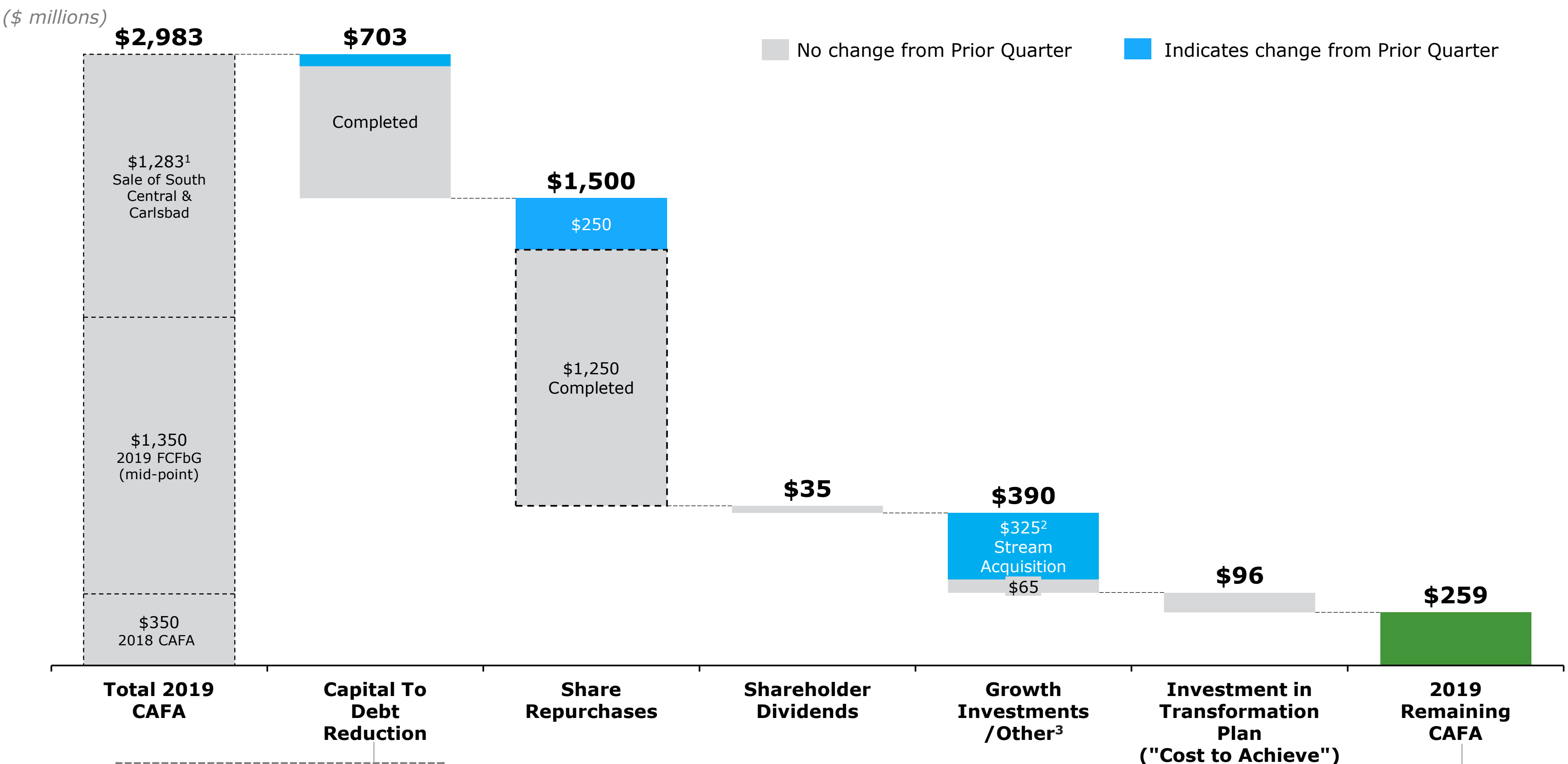
Integrated Platform

Highlights:

- Completed entire 2019 $1.25 Bn share repurchase program at an average price of $38.80 per share
- Completed $600 MM deleveraging, and refinanced term loan and nearest maturity 2024 notes resulting in ~$25 MM in annual interest savings
- Reaffirming 2019 guidance ranges

[1] Includes Corporate segment; [2] See slide 31 for details of on asset sales/deconsolidation; [3] Primarily higher 2018 emission credit sales

2019 Capital Allocation



Debt reduction and term loan amortization[4]	$ 598
Debt premiums and fees	57
Midwest Gen Debt amortization[5]	48

Up to $124 MM Petra Nova reserve/guarantee

>50% of Capital Allocated to Return to Shareholders; ~75% Allocated to Return to Shareholders and Balance Sheet Improvement

[1] See appendix slide 29 for details; net of transaction fees and other adjustments; [2] Includes $25 MM estimated transaction fees and working capital adjustments; [3] Includes $15 MM for GenOn pension funding for 2019; [4] Includes $4MM of term loan amortization; [5] $48 MM of 2019 capacity revenue sold forward in 2016; 2019 payment to counterparty treated as debt amortization for accounting purposes

Corporate Credit Profile/New Targets

($ millions)

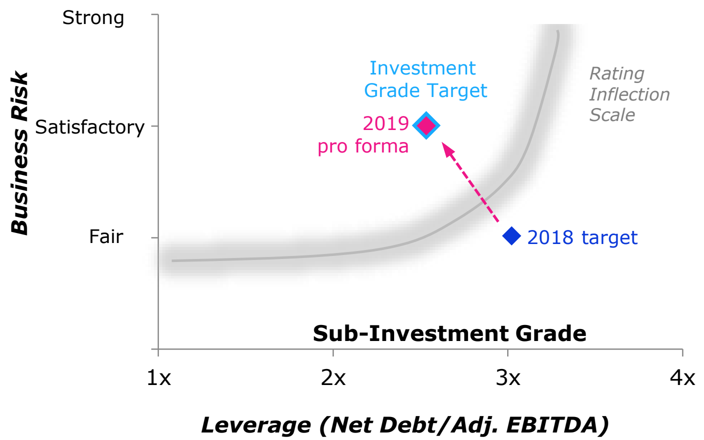
	2019 Guidance
Corporate Debt[1]	**$5,925**
Cash & Cash Equivalents[2]	(500)
Corporate Net Debt	**~$5,425**
Adj. EBITDA[3]	**$1,950**
Less: MWG Adj. EBITDA[4], net of cash distribution	(30)
Other Adjustments[5]	150
Corporate Adj. EBITDA	**$2,070**
Net Debt / Adj. EBITDA	**2.50 - 2.75x**
Adj. CFO / Net Debt	**27.5 - 32.5%**
(Adj. CFO + Interest) / Interest	**5.5 - 6.5x**

Stream Pro Forma

Adj. EBITDA **$65 MM**

Net Debt / Adj EBITDA **2.5x**

Illustrative NRG Credit Profile



- Further enhances financial risk profile
- Reduces cost of capital
- Accretive to FCFbG (2%)

$600 MM Debt Reduction Enables Achievement of Investment Grade Metrics in 2019

[1] Balance at 06/30/2019; [2] 2019 comprises minimum cash assuming excess capital is fully deployed; [3] Midpoint of 2019 guidance range; [4] Adjusted EBITDA of $135 MM less distributions of $105 MM; [5] Includes non-cash expenses (i.e. nuclear amortization, equity compensation amortization, and bad debt expense) that are included in Adjusted EBITDA

Closing Remarks

2019 Priorities

- ☐ **Deliver on Financial and Operational Objectives**
  - ☑ Strong year-to-date financial, operational and safety performance

- ☐ **Execute on NRG Transformation Plan 2019 Objectives**
  - ☐ $590 MM cumulative EBITDA-accretive cost savings – on track
  - ☐ $135 MM cumulative EBITDA-accretive margin enhancement – on track

- ☐ **Continue to Perfect Customer-Focused Business Model**
  - ☑ ***New*** Executed ~1.3 GW of Solar PPAs at attractive economics
  - ☑ ***New*** Closed on acquisition of Stream Energy
  - ☑ ***New*** Gregory, 385 MW CCGT, returned to service

- ☐ **Adhere to Disciplined Capital Allocation Strategy**
  - ☐ ***New*** Execute incremental $250 MM share repurchase program by year-end
  - ☑ ***New*** Achieved investment grade credit metrics with $600 MM in deleveraging
  - ☑ ***New*** Completed $1 Bn share repurchase program, $1.25 Bn year-to-date

Appendix

Transformation Plan
Scorecard Update

Scorecard as of 6/30/2019

($ millions)	2019 Realized	2019 % Achieved	2019 Target
Accretive & Recurring:			
Cost Savings	261	*44%*	590
Margin Enhancement	30	*22%*	135
Total EBITDA - Accretion	**$291**	***40%***	**$725**
Maintenance Capex	20	*40%*	50
Total Recurring FCFbG - Accretion	**$311**	***40%***	**$775**
Non-Recurring:			
Working Capital Improvement	29	*78%*	37
Cost to Achieve Total Transformation Plan	(45)	-	(96)
Total Non-Recurring	**($16)**	**-**	**($59)**
Annual Cash Accretion	**$295**	***41%***	**$716**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$1,195**	***74%***	**~$1,616**

Transformation Plan Progress

($ millions)	2017 Realized	2018 Realized	2019 Target	2020 / Run Rate
Accretive & Recurring:				
Cost Savings	150	532	590	590
Margin Enhancement*	-	32	135	215
Total EBITDA –Accretion	**$150**	**$564**	**$725**	**$805**
Maintenance Capex*	-	47	50	50
Total Recurring FCFbG - Accretion	**$150**	**$611**	**$775**	**$855**
Non-Recurring:				
Working Capital Improvement[1]	221	112	37	--
Cost to Achieve Total Transformation Plan[2]	(44)	(150)	(96)	--
Total Non-Recurring	**$177**	**($38)**	**($59)**	**--**
Annual Cash Accretion	**$327**	**$573**	**$716**	**$855**
Cumulative Cash Accretion *(Incremental Capital Available for Allocation)*	**$327**	**$900**	**~$1,616**	**~$2,471**

* **On track:** no stated target in 2017 per plan announced 7/12/2017

[1] 2019 Working Capital Improvement target updated from $49 MM at 3Q18 earnings due to achievement levels in 2017 and 2018; total target did not change and remains $370 MM; [2] 2019 Cost to Achieve Total Transformation Plan target updated from $60 MM at 3Q18 earnings due to achievement levels in 2017 and 2018; total remains $290 MM

Committed to Sustainability

NRG Sustainability Framework

Sustainable Business

Sustainable Operations

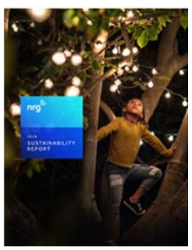
Sustainable Customers

Sustainable Suppliers

Sustainable Workplace

Industry-Leading Disclosure

SASB



TCFD

Comprehensive Approach

Sustainable Development Goals

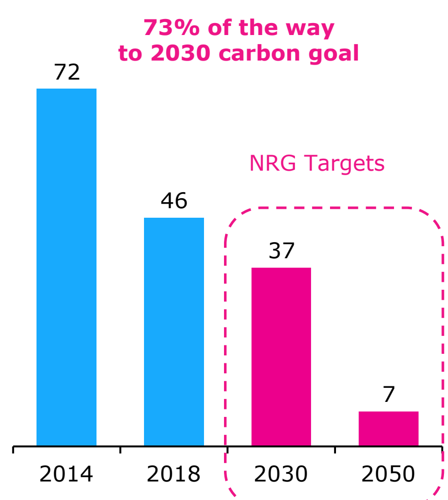
CDP Supplier Engagement Leader

Science Based Targets – Driving Ambitious Corporate Climate Action

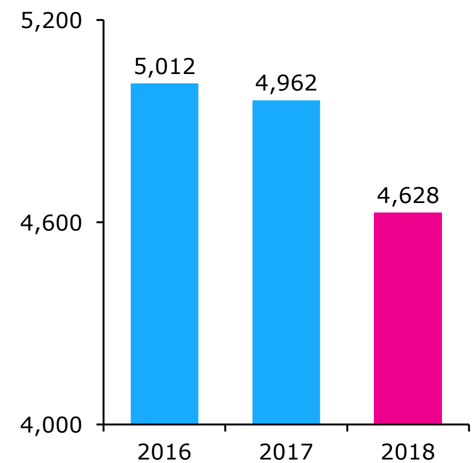
Women's Empowerment Principles – Equality Means Business

Environmental Leadership[1]

U.S. CO_2e Emission Goals ($MMtCO_2e$[2])



Revenue Carbon Intensity (tCO_2e[3]/$ MM)



[1] As of December 31, 2018; NRG's goal is to reduce its total U.S. Scope 1, 2 (purchased electricity) and 3 (business travel) CO_2e emissions by 50% by 2030, and by 90% by 2050, using 2014 as a baseline; [2] Million Metric tons of carbon dioxide equivalent; [3] Tons of carbon dioxide equivalent

Appendix: Operations

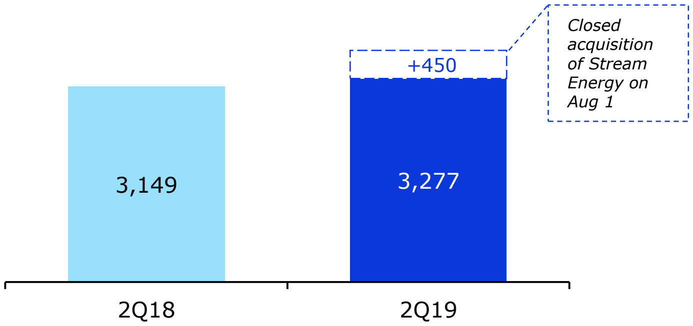
Retail: Operational Metrics

Q2 Highlights

- Delivered $240 MM in Adjusted EBITDA for the quarter, down from last year primarily driven by higher supply costs, milder weather and capacity obligations, partially offset by transformation plan cost and margin benefits
- Suppressed loads driven by the 8th wettest Q2 in Texas over the past 125 years and cool temps
- Launched innovative and compelling electricity offers and tools like Reliant/NRG energy management solutions leveraging Google/Nest, the Green Mountain app and Rent Ready by Reliant

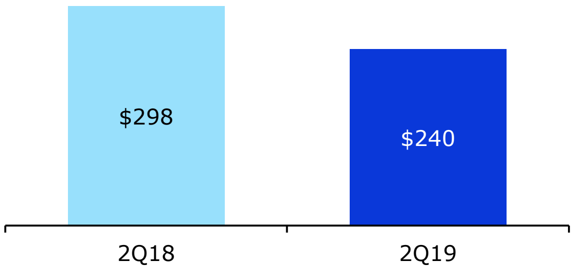
Mass Customer Count

Mass Recurring Customers[1] (000s)



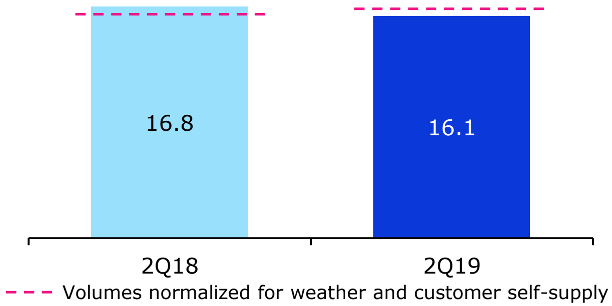
Retail Adjusted EBITDA

Adjusted EBITDA ($ millions)



Delivered Volumes

Delivered TWh



On Track to Deliver Another Year of Retail Earnings Growth

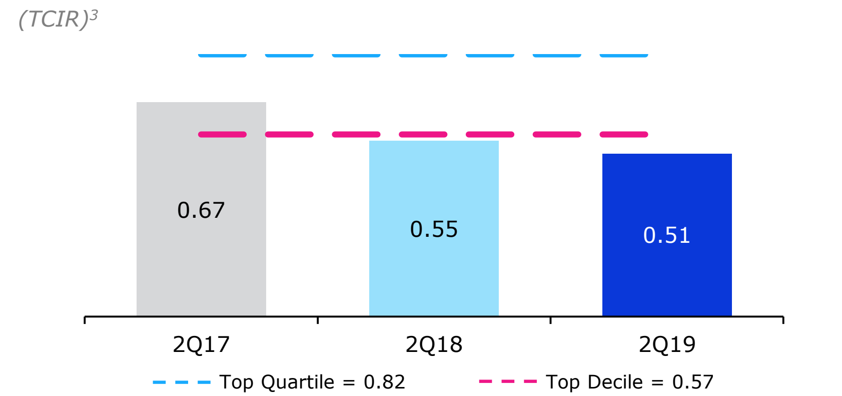
[1] Mass recurring customer count includes customers that subscribe to one or more recurring services, such as electricity and natural gas; excludes C&I customers

Generation: Operational Metrics

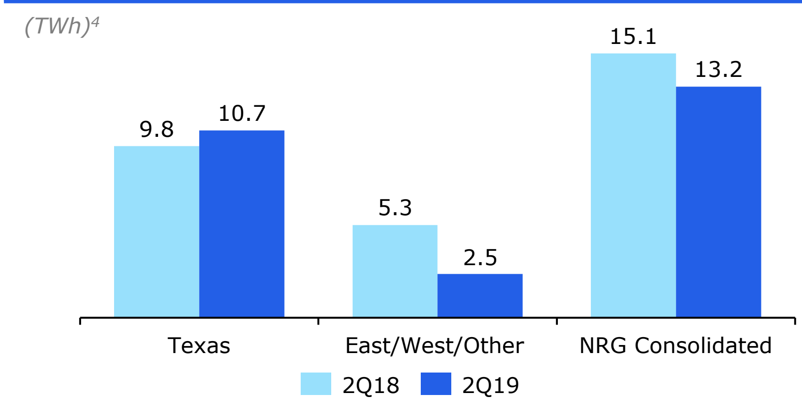
Q2 Highlights

- Successful completion of Gregory return to service for summer operation
- Delivered top decile safety performance
- Delivered $229 MM[1] in Adjusted EBITDA for the quarter; up $10 MM Y/Y driven by $75 MM increase from higher power prices partially offset by $56 MM decrease due to asset sales & deconsolidations[2]

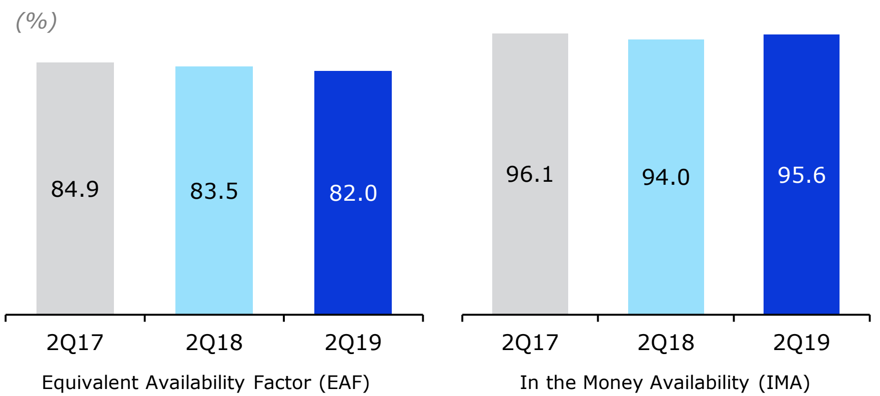
Safety[1]



Production



Coal/Nuclear EAF and In the Money Availability



Focus on Safety and Operational Execution Continues to Drive Results

[1] Includes Corporate segment; [2] See slide 31; [3] Excludes Goal Zero, NRG Home Services & Security; top decile and top quartile based on Edison Electric Institute 2017 Total Company Survey results; [2] TCIR = Total Case Incident Rate; [4] All NRG-owned domestic generation; excludes line losses, station service, and other items. Generation data presented above consistent with GAAP and excludes discontinued operations

Wholesale Total Gross Margin

Total Portfolio[1]	ERCOT		East/West[2]	
	Bal 2019[1]	2020	Bal 2019[1]	2020
Total Capacity (MW)[3]	10,042	10,042	11,417	11,417
Estimated Generation (GWh)[4]	20,982	41,366	9,889	16,458
Percentage Hedged[5]	**105%**	**70%**	**109%**	**48%**
Gross Margin Summary ($ MM)				
Open Energy Gross Margin[6]	$606	$1,017	$121	$217
Mark-to-Market of Hedges[7]	$123	$67	$24	$12
Total Energy Gross Margin	**$729**	**$1,084**	**$145**	**$229**
Capacity Revenue[8]	--	--	$295	$569
Wholesale Total Gross Margin	**$729**	**$1,084**	**$440**	**$798**
Gross Margin Sensitivity ($ MM)				
Gas Price Sensitivity up $0.50/MMBtu[9]	**<$5**	**$38**	**$33**	**$99**
Gas Price Sensitivity Down $0.50/MMBtu[9]	**>($5)**	**($77)**	**$9**	**($41)**
Heat Rate Sensitivity up 1 MMBtu/MWh[10]	**$9**	**$76**	**$23**	**$72**
Heat Rate Sensitivity Down 1 MMBtu/MWh[10]	**($6)**	**($69)**	**($9)**	**($48)**

1 Portfolio as of 6/28/2019, excludes equity interest assets. Bal 2019 represents July through December
2 Includes Cottonwood
3 Total capacity represents net summer dependable MW capacity of plants after adjusting for the Company's ownership position excluding capacity from inactive/mothballed units
4 Estimated generation represents expected generation dispatch output (GWh) based on forward price curves as of 6/28/2019 and takes into account planned and unplanned outage assumptions
5 Percentage hedged represents the portion of the portfolio that is hedged using forward power & natural gas sales contracts; Any forward natural gas for power hedges are reflected in power equivalent based on forward market implied heat rate as of 6/28/2019 after adjusting for correlation between forward power and natural gas prices which is then combined with power sales to arrive at total power equivalent hedge volume; % hedged is based on the power equivalent hedge volumes divided by estimated generation (4); Excludes the extent of coal hedging – NRG is hedged 100% and 32% of its coal fuel requirement for 2019 & 2020 respectively.
6 Open Energy Gross Margin represents the expected revenue net of fuel and emission costs from merchant conventional fleet based upon a dispatch model that uses forward power and fuel curves and makes assumptions on hourly price path and planned/unplanned outage events.
7 Mark to Market of hedges represents the current fair value of power and fuel hedges and is calculated by multiplying the difference between the current forward price and the transaction price with the volume of the transaction. This includes all inter-segment sales executed between the generation segment to retail segment; 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 2018 10K Item 15 - Note 5, Accounting for Derivative Instruments and Hedging Activities.
8 Capacity revenue represents revenue from MWs cleared in ISO auctions or sold bilaterally plus forecasted revenue from unsold capacity. For details please refer to the slide on Capacity Clears & Unsold in the deck.
9 Gas Price Sensitivity represents Gross Margin change from $0.5/MMBtu gas price change, keeping heat rates unchanged
10 Heat Rate Sensitivity represents Gross Margin change from 1 HR change in annual RTC power prices, keeping natural gas prices unchanged. The change in heat rate is shaped by the level of the current forward curve – that is higher priced months experience a bigger change in heat rate while lower priced months experience a smaller change.

Commodity Prices

	Bal 2019[1]		2020	
Reference Prices 6/28/2019	**Reference Price**	**Market Heat Rate[1]**	**Reference Price**	**Market Heat Rate[1]**
Natural Gas Henry Hub ($/MMBtu)	$2.36	--	$2.54	--
PRB 8800 Coal ($/Ton)	$12.35	--	$12.40	--
	$/MWh	**MMBtu/MWh**	**$/MWh**	**MMBtu/MWh**
ERCOT Houston Around-the-Clock ($/MWh)	$32.22	13.6	$30.92	12.2
PJM West Around-the-Clock ($/MWh)	$25.97	11.0	$27.61	10.9

[1] Bal 2019 represents July through December

Capacity Clears & Unsold

Capacity Revenue by Calendar Year ($ MM)

Market	2019	2020
PJM	$317	$282
ISO-NE	$149	$110
NYISO[1]	$107	$145
CAISO[1]	$25	$32

Illustrative: Assumes uncleared capacity clears at current market levels

Market	Region	Planning Year	Average Price ($/kW-Month)	Estimated Qualified Capacity[2]	Percentage Sold[3]	MWs Cleared
ISO-NE	Connecticut	2018-2019	$9.55	1,535	100%	1,535
		2019-2020	$7.03	1,529	100%	1,529
		2020-2021	$5.30	1,529	100%	1,529
		2021-2022	$4.63	1,529	100%	1,529
		2022-2023	$3.80	1,517	100%	1,517
NYISO		2019	$3.23	2,756	97%	2,682
		2020	$4.52	2,674	59%	1,585
CAISO		2019	$2.49	838	100%	838
		2020	$3.15	838	18%	150

[1] NYISO & CAISO values include sold and unsold revenue; unsold revenue is estimated as of 6/28/2019 and is subject to change; NYC estimated qualified capacity is ~1.2 GW; NYISO – Rest of State estimated qualified capacity is ~1.5 GW; [2] Capacity that can be bid in a capacity auction; estimated as of 6/28/2019 and is subject to change; [3] Percentage of the total qualified capacity that has been sold as of 6/28/2019

PJM Capacity Clears

Capacity Revenue by Calendar Year ($ MM)

Market	2019	2020	2021
PJM	$317	$282	$299

Capacity Revenue by Delivery Year ($ MM)

Market	18/19	19/20	20/21	21/22
PJM	$334	$305	$265	$322

			Base Product		Capacity Performance Product	
Market	**Region**	**Planning Year**	**Average Price ($/MW-Day)**	**MWs Cleared**	**Average Price ($/MW-Day)**	**MWs Cleared**
PJM	ComEd	2018-2019	$25.58	221	$215.00	3,509
		2019-2020	$182.77	65	$202.77	3,738
		2020-2021			$188.12	3,315
		2021-2022			$195.55	3,995
PJM	DPL South	2018-2019	$210.63	98	$217.08	481
		2019-2020	NA	NA	$119.77	481
		2020-2021			$187.87	519
		2021-2022			$165.73	552
PJM	PEPCO	2018-2019	NA	NA	$229.10	46
		2019-2020	NA	NA	$100.00	66
		2020-2021			$86.04	67
		2021-2022			$140.00	72
PJM	Net Total	2018-2019	$82.51	319	$220.21	4,035
		2019-2020	$182.77	65	$191.89	4,284
		2020-2021			$186.34	3,901
		2021-2022			$191.12	4,619

Assumptions:

- PJM Data as of 5/23/2018
- Represents merchant wholesale generation

Q2 & YTD 2019 Generation & Operational Performance Metrics

2Q19 (MWh 000's)	2Q19 Generation[1]	2Q18 Generation[1]	MWh Change	% Change	2Q19 EAF[2]	2Q19 NCF[3]	2Q18 EAF[2]	2Q18 NCF[3]
Texas	10,645	9,848	796	8%	84%	48%	83%	46%
East/West[4]	2,536	5,255	(2,719)	(52%)	75%	10%	83%	18%
Total	**13,180**	**15,103**	**(1,923)**	**(13%)**	**79%**	**28%**	**83%**	**30%**
Texas Nuclear	2,522	2,136	386	18%	100%	100%	85%	84%
Texas Coal	6,402	6,555	(153)	(2%)	89%	70%	91%	72%
East Coal	480	1,829	(1,350)	(74%)	66%	7%	73%	23%
Coal/Nuclear	**9,404**	**10,521**	**(1,117)**	**(11%)**	**82%**	**51%**	**83%**	**56%**
Texas Gas	1,720	1,157	563	49%	77%	16%	75%	12%
East Oil	13	59	(46)	(77%)	78%	0%	78%	1%
East Gas[5]	2,011	2,400	(388)	(16%)	86%	24%	91%	28%
West Gas	29	678	(648)	(96%)	43%	2%	93%	18%
Oil/Gas	**3,774**	**4,293**	**(519)**	**(12%)**	**78%**	**13%**	**83%**	**14%**
Renewables	**2**	**289**	**(287)**	**(99%)**				

2019 YTD (MWh 000's)	2019 Generation[1]	2018 Generation[1]	MWh Change	% Change	2019 EAF[2]	2019 NCF[3]	2018 EAF[2]	2018 NCF[3]
Texas	18,280	17,304	976	6%	82%	41%	82%	41%
East/West[4]	6,957	9,957	(3,000)	(30%)	81%	14%	84%	16%
Total	**25,236**	**27,261**	**(2,025)**	**(7%)**	**81%**	**26%**	**83%**	**27%**
Texas Nuclear	5,060	4,451	609	14%	100%	100%	91%	87%
Texas Coal	11,009	11,162	(154)	(1%)	82%	61%	83%	62%
East Coal	2,807	3,661	(854)	(23%)	76%	21%	78%	24%
Coal/Nuclear	**18,875**	**19,274**	**(399)**	**(2%)**	**82%**	**51%**	**82%**	**51%**
Texas Gas	2,211	1,691	520	31%	79%	10%	79%	9%
East Oil	18	234	(217)	(92%)	86%	0%	86%	1%
East Gas[5]	3,863	4,325	(461)	(11%)	87%	23%	88%	25%
West Gas	259	1,116	(857)	(77%)	44%	7%	84%	15%
Oil/Gas	**6,351**	**7,366**	**(1,015)**	**(14%)**	**81%**	**11%**	**84%**	**12%**
Renewables	**10**	**621**	**(611)**	**(98%)**				

[1] Excludes line losses, station service and other items; [2] EAF – Equivalent Availability Factor; [3] NCF – Net Capacity Factor; [4] Includes Cottonwood and renewable assets. International is excluded from this table; [5] Includes the 1,153 MW Cottonwood facility

Asset List[1]

ERCOT

ERCOT (10,061 MW, Net)		
Name	**Capacity**	**Ownership**
Cedar Bayou	1,494	100%
Cedar Bayou 4	252	50%
Elbow Creek (Battery Storage)	2	100%
Greens Bayou	330	100%
Gregory	385	100%
Limestone	1,660	100%
Petra Nova[2]	19	50%
San Jacinto	160	100%
South Texas	1,126	44%
T.H. Wharton	1,001	100%
W.A. Parish	3,632	100%

MISO

MISO (1,153 MW, Net)		
Name	**Capacity**	**Ownership**
Cottonwood	1,153	Lease thru 2025

CAISO

CAISO (1,155 MW, Net)		
Name	**Capacity**	**Ownership**
Long Beach	252	100%
Midway Sunset[2]	113	50%
Sunrise	586	100%
Watson[2]	204	49%

PJM

ComEd (4,319 MW, Net)		
Name	**Capacity**	**Ownership**
Fisk	171	100%
Joliet	1,317	100%
Powerton	1,538	100%
Waukegan	783	100%
Will County	510	100%

DPL (593 MW, Net)		
Name	**Capacity**	**Ownership**
Indian River	426	100%
Vienna	167	100%

PEPCO (80 MW, Net)		
Name	**Capacity**	**Ownership**
Chalk Point (SMECO)	80	100%

NYISO

NYC (1,289 MW, Net)		
Name	**Capacity**	**Ownership**
Arthur Kill	866	100%
Astoria	423	100%

Central (1,617 MW, Net)		
Name	**Capacity**	**Ownership**
Oswego	1,617	100%

ISO-NE

Connecticut (1,528 MW, Net)		
Name	**Capacity**	**Ownership**
CT Jets	142	100%
Devon	133	100%
Middletown	762	100%
Montville	491	100%

Renewables

Renewables (381 MW, Net)		
Name	**Capacity**	**Ownership**
Agua Caliente[2]	102	35%
Ivanpah[2]	214	55%
Stadiums	5	100%
Resi-Solar	60	100%

International

International (605 MW, Net)		
Name	**Capacity**	**Ownership**
Gladstone[2]	605	38%

[1] As of 6/30/2019; [2] Equity investments

Appendix: Finance

Q2 2019 YTD Capital Expenditures

($ millions)

	Maintenance	Environmental	Growth[1]	Total
Retail	$9	$ -	$19	$28
Generation				
Texas	39	-	-	39
East/West[2]	25	2	-	27
Corporate	3	-	10	13
Total Cash Capital Expenditures	**$76**	**$2**	**$29**	**$107**
Other Investments[3]	-		58	58
Total Capital Expenditures and Growth Investments (including CTA)	**$76**	**$2**	**$87**	**$165**
Total Capital Expenditures and Growth Investments (excluding CTA capex)	***$76***	***$2***	***$60***	***$138***

[1] Includes cost-to-achieve spend of $27 MM; [2] Includes International, Renewables and Cottonwood; [3] Primarily includes Retail small book acquisitions and Carlsbad

Recourse / Non-Recourse Debt

($ millions)

	6/30/2019	12/31/2018
Recourse Debt		
Term Loan Facility	$ -	$ 1,698
Senior Notes	3,784	3,784
Convertible Notes	575	575
Senior Secured First Lien Notes	1,100	-
Tax Exempt Bonds	466	466
Revolver	-	-
Capital Lease	1	1
Corporate Debt Subtotal	**$ 5,926**	**$ 6,524**
Non-Recourse Debt		
Renewables[1] (including capital leases)	112	115
Conventional[2]	5	53
Non-Recourse Debt Subtotal	**$ 117**	**$ 168**
Total Debt	**$ 6,043**	**$ 6,692**

Note: Debt balances exclude discounts and premiums
[1] Balance as of 6/30/2019 includes $83 MM of Agua Borrower I debt; [2] Includes Midwest Gen capacity monetization debt as of 12/31/18

Announced Asset Sales

($ millions)

	Status	2017	2018	2019	Total
Transformation Plan Asset Sales[1]:					
Asset Sales in 2H17[2]	Closed	$150	$-	$-	$150
Renewables / NRG Yield Interest	Closed	-	1,348	-	1,348
Buckthorn Solar	Closed	-	42	-	42
BETM	Closed	-	70	-	70
Other[3]	Closed	-	24	8	32
South Central	Closed	-	-	1,000	1,000
Carlsbad	Closed	-	-	385	385
Transformation Plan Total Proceeds		**150**	**1,484**	**1,393**	**3,027**
Asset Sales Outside of Transformation Plan:					
Canal 3[4]	Closed	-	130	-	130
Total Net Proceeds		**$150**	**$1,614**	**$1,393**	**$3,157**

[1] Excludes working capital, transaction fees and other adjustments totaling ~$145 MM; [2] Includes drop down proceeds for TE Holdco (25%) $42 MM and SPP $71 MM to Clearway Energy, Inc. and sale proceeds for MN Wind $37 MM; [3] Includes Spanish Town, Keystone & Conemaugh, Eastridge, Saguaro and Guam; [4] Canal 3 reflects sale and debt proceeds in excess of the original growth investment guidance

Incremental Transformation Plan

($ millions)

	2017A	2018A	2019E	2020E
Cost Savings	$150	$532	$590	$590
Margin Enhancements	-	32	135	215
EBITDA Impact	**$150**	**$564**	**$725**	**$805**
Maintenance Capex	-	47	50	50
Working Capital	221	112	37	-
FCFbG Impact	**$371**	**$723**	**$812**	**$855**
Incremental EBITDA Change		*414*	*161*	*80*
Incremental FCFbG Change		*352*	*89*	*43*

Portfolio Changes

- As a result of the Transformation Plan, NRG monetized and deconsolidated numerous non-core businesses. The 2018 results were recast for the NRG Yield / Renewables and South Central asset sales but not for the smaller asset sales and deconsolidation of certain projects. The below table highlights the financial impact of assets sold and deconsolidated as reflected in 2018 Adjusted EBITDA.

($ in Millions)	***1Q18***	***2Q18***	***3Q18***	***4Q18***	***FY2018***
Agua Caliente/Ivanpah deconsolidation[1]	$ 23	$ 22	$ 18	-	$ 63
BETM[2]	12	14	4	-	30
Cottonwood leaseback[3]	7	10	10	10	37
Encina deactivation	5	10	25	8	48
Total Adjusted EBITDA	**$ 47**	**$ 56**	**$ 57**	**$ 18**	**$ 178**

[1] Ivanpah was deconsolidated in April 2018 and Agua Caliente was deconsolidated in August 2018; [2] BETM sold on August 1, 2018; [3] Pro-forma to reflect lease expense incurred from date of sale of South Central Portfolio

Appendix: Reg. G Schedules

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Appendix Table A-1: 2019 Guidance
The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Adjusted EBITDA

($ millions)	**2019 Guidance**
Total Adjusted EBITDA	**$1,850 - $2,050**
Interest payments	(335)
Income tax	(15)
Working capital / other assets and liabilities	(95)
Adjusted Cash Flow from Operations	**$1,405 - $1,605**
Maintenance capital expenditures, net	(145) – (165)[1]
Environmental capital expenditures, net	(0) - (5)
Free Cash Flow before Growth	**$1,250 - $1,450**

[1] Includes ~$25 MM for TX reliability projects and inclusion of Cottonwood

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Appendix Table A-2: Q2 2019 YTD Free Cash Flow before Growth
The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Cash provided by continuing operations

($ millions)		YTD 6/30/2019
Adjusted EBITDA	**$**	**801**
Interest payments		(149)
Collateral / working capital / other		(271)
Cash provided by continuing operations	**$**	**381**
Cost-to-Achieve[1]		18
GenOn Settlement[2]		5
Collateral		(123)
Adjusted Cash Flow from Operations	**$**	**282**
Maintenance capital expenditures, net		(76)
Environmental capital expenditures, net		(2)
Free Cash Flow before Growth	**$**	**204**

[1] Includes costs associated with the Transformation Plan announced on 7/12/2017; [2] Includes final restructuring fee of $5 million

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Appendix Table A-3: Q2 2019 QTD Free Cash Flow before Growth
The following table summarizes the calculation of Free Cash Flow before Growth and provides a reconciliation to Cash provided by continuing operations

($ millions)		QTD 6/30/2019
Adjusted EBITDA	**$**	**469**
Interest payments		(65)
Collateral / working capital / other		112
Cash provided by continuing operations	**$**	**516**
Cost-to-Achieve[1]		2
Collateral		(246)
Adjusted Cash Flow from Operations	**$**	**272**
Maintenance capital expenditures, net		(41)
Environmental capital expenditures, net		(1)
Free Cash Flow before Growth	**$**	**230**

[1] Includes costs associated with the Transformation Plan announced on 7/12/2017

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Appendix Table A-4: Second Quarter 2019 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**539**	**79**	**618**	**(280)**	**(149)**	**189**
Plus:						
Interest expense, net	-	6	6	1	92	99
Income tax	-	-	-	1	(2)	(1)
Loss on debt extinguishment	-	-	-	-	47	47
Depreciation and amortization	22	23	45	32	8	85
ARO Expense	3	4	7	-	-	7
Contract amortization	6	-	6	-	-	6
EBITDA	**570**	**112**	**682**	**(246)**	**(4)**	**432**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	5	28	33	-	-	33
Acquisition-related transaction & integration costs	-	-	-	-	1	1
Reorganization costs	-	-	-	2	-	2
Legal Settlement	3	8	11	-	-	11
Deactivation costs	-	7	7	-	2	9
Other non-recurring charges	-	2	2	(1)	-	1
Impairments	-	-	-	1	-	1
Mark to market (MtM) (gains)/losses on economic hedges	(444)	(61)	(505)	484	-	(21)
Adjusted EBITDA	**134**	**96**	**230**	**240**	**(1)**	**469**

[1] Includes International, remaining renewables and Generation eliminations

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Appendix Table A-5: Second Quarter YTD 2019 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**582**	**149**	**731**	**(170)**	**(278)**	**283**
Plus:						
Interest expense, net	-	13	13	1	192	206
Income tax	-	1	1	1	1	3
Loss on debt extinguishment	-	-	-	-	47	47
Depreciation and amortization	43	48	91	63	16	170
ARO Expense	7	7	14	-	-	14
Contract amortization	11	-	11	-	-	11
EBITDA	**643**	**218**	**861**	**(105)**	**(22)**	**734**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	8	57	65	-	-	65
Acquisition-related transaction & integration costs	-	-	-	1	-	1
Reorganization costs	-	1	1	3	11	15
Legal Settlement	3	8	11	-	-	11
Deactivation costs	-	8	8	-	5	13
Other non-recurring charges	(1)	2	1	1	-	2
Impairments	-	-	-	1	-	1
Mark to market (MtM) (gains)/losses on economic hedges	(475)	(58)	(533)	492	-	(41)
Adjusted EBITDA	**178**	**236**	**414**	**393**	**(6)**	**801**

[1] Includes International, remaining renewables and Generation eliminations

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Appendix Table A-6: Second Quarter 2018 Adjusted EBITDA Reconciliation by Operating Segment

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**286**	**(34)**	**252**	**(84)**	**(141)**	**27**
Plus:						
Interest expense, net	-	15	15	1	105	121
Income tax	-	1	1	-	4	5
Loss on debt extinguishment	-	-	-	-	1	1
Depreciation and amortization	21	53	74	30	8	112
ARO Expense	4	4	8	-	1	9
Contract amortization	7	-	7	-	-	7
Lease amortization	-	(2)	(2)	-	-	(2)
EBITDA	**318**	**37**	**355**	**(53)**	**(22)**	**280**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	3	15	18	-	-	18
Acquisition-related transaction & integration costs	-	-	-	1	-	1
Reorganization costs	1	2	3	1	19	23
Legal Settlement	13	-	13	-	6	19
Deactivation costs	-	7	7	-	3	10
Gain on sale of business	-	-	-	-	(16)	(16)
Other non-recurring charges	-	4	4	3	(3)	4
Impairments	6	95	101	-	1	102
Mark to market (MtM) (gains)/losses on economic hedges	(293)	23	(270)	346	-	76
Adjusted EBITDA	**48**	**183**	**231**	**298**	**(12)**	**517**

[1] Includes International, remaining renewables and Generation eliminations

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Appendix Table A-7: Second Quarter YTD 2018 Adjusted EBITDA Reconciliation by Operating Segment
The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	Texas	East/ West [1]	Generation	Retail	Corp/ Elim	Total
Income/(Loss) from Continuing Operations	**(314)**	**(5)**	**(319)**	**860**	**(276)**	**265**
Plus:						
Interest expense, net	-	36	36	2	195	233
Income tax	-	-	-	-	11	11
Loss on debt extinguishment	-	-	-	-	3	3
Depreciation and amortization	42	118	160	56	16	232
ARO Expense	11	8	19	-	1	20
Contract amortization	12	1	13	-	-	13
Lease amortization	-	(4)	(4)	-	-	(4)
EBITDA	**(249)**	**154**	**(95)**	**918**	**(50)**	**773**
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	2	23	25	-	1	26
Acquisition-related transaction & integration costs	-	-	-	1	4	5
Reorganization costs	2	4	6	5	32	43
Legal Settlement	13	-	13	-	6	19
Deactivation costs	-	10	10	-	5	15
Gain on sale of business	-	1	1	-	(17)	(16)
Other non-recurring charges	-	5	5	2	-	7
Impairments	15	95	110	-	1	111
Mark to market (MtM) (gains)/losses on economic hedges	278	32	310	(440)	-	(130)
Adjusted EBITDA	**61**	**324**	**385**	**486**	**(18)**	**853**

[1] Includes International, remaining renewables and Generation eliminations

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Appendix Table A-8: 2019 Adjusted EBITDA Guidance Reconciliation: The following table summarizes the calculation of Adjusted EBITDA providing reconciliation to Income from Continuing Operations:

	2019 Adjusted EBITDA Guidance	
($ millions)	**Low**	**High**
Income from Continuing Operations[1]	940	1,140
Income tax	15	15
Interest Expense	335	335
Depreciation, Amortization, Contract Amortization, and ARO Expense	430	430
Adjustment to reflect NRG share of adjusted EBITDA in unconsolidated affiliates	80	80
Other Costs[2]	50	50
Adjusted EBITDA	**$1,850**	**$2,050**

[1] For purposes of guidance fair value adjustments related to derivatives are assumed to be zero; [2] 2019 includes deactivation costs and cost-to-achieve expenses

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Appendix Table A-9: Full Year 2019 Adjusted EBITDA Reconciliation for Midwest Gen

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	**2019**
Income/(Loss) from Continuing Operations	**95**
Plus:	
Depreciation, Amortization, Contract Amortization, and ARO Expense	40
EBITDA	**135**
Plus: Operating lease expense	22
Adjusted EBITDAR	**157**
Less: Operating lease expense	(22)
Adjusted EBITDA	**$135**

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Appendix Table A-10: Run-Rate Adjusted EBITDA Reconciliation for Stream Energy

The following table summarizes the calculation of Adjusted EBITDA and provides a reconciliation to Income/(Loss) from Continuing Operations

($ millions)	**Run-Rate**
Income/(Loss) from Continuing Operations	**41**
Plus:	
Depreciation, Amortization, Contract Amortization, and ARO Expense	21
EBITDA	**62**
Acquisition-related transaction & integration costs	3
Adjusted EBITDA	**$65**

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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.