AUSTIN ENERGY®

INVESTING IN A CLEAN FUTURE

Austin Energy's Resource, Generation and Climate Protection Plan to 2020 Update

May 7, 2014

INVESTING IN A CLEAN FUTURE

Austin Energy Briefing to Austin Generation Resource Planning Task Force

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May 7, 2014

Agenda

- Historical Average Fuel & Production Costs
- List of Scenarios
- Month Wholesale real time market purchases
  - January 2011 through December 2013

Historical Average Fuel Cost & Production Cost

Austin Energy historical average fuel and production cost is available @

- http://austinenergy.com/wps/portal/ae/about/reports-and-data-library/data-library
- Also available at 2012 Annual Performance Report
  - Table 38: Fuel Costs (Page 32 of 53 of the report)
  - Table 46: System Fuel Cost Average (Page 38 of 53 of the report)
  - Table 47: System Production Cost (Page 38 of 53 of the report)
  - Table 49: Plant Outages (Page 39 of 53 of the report)

Historic Average Fuel & Production Costs

- System fuel average cost is the cost of fuel purchased divided by the number of kilowatts generated.

Table 46: System Fuel Cost Average

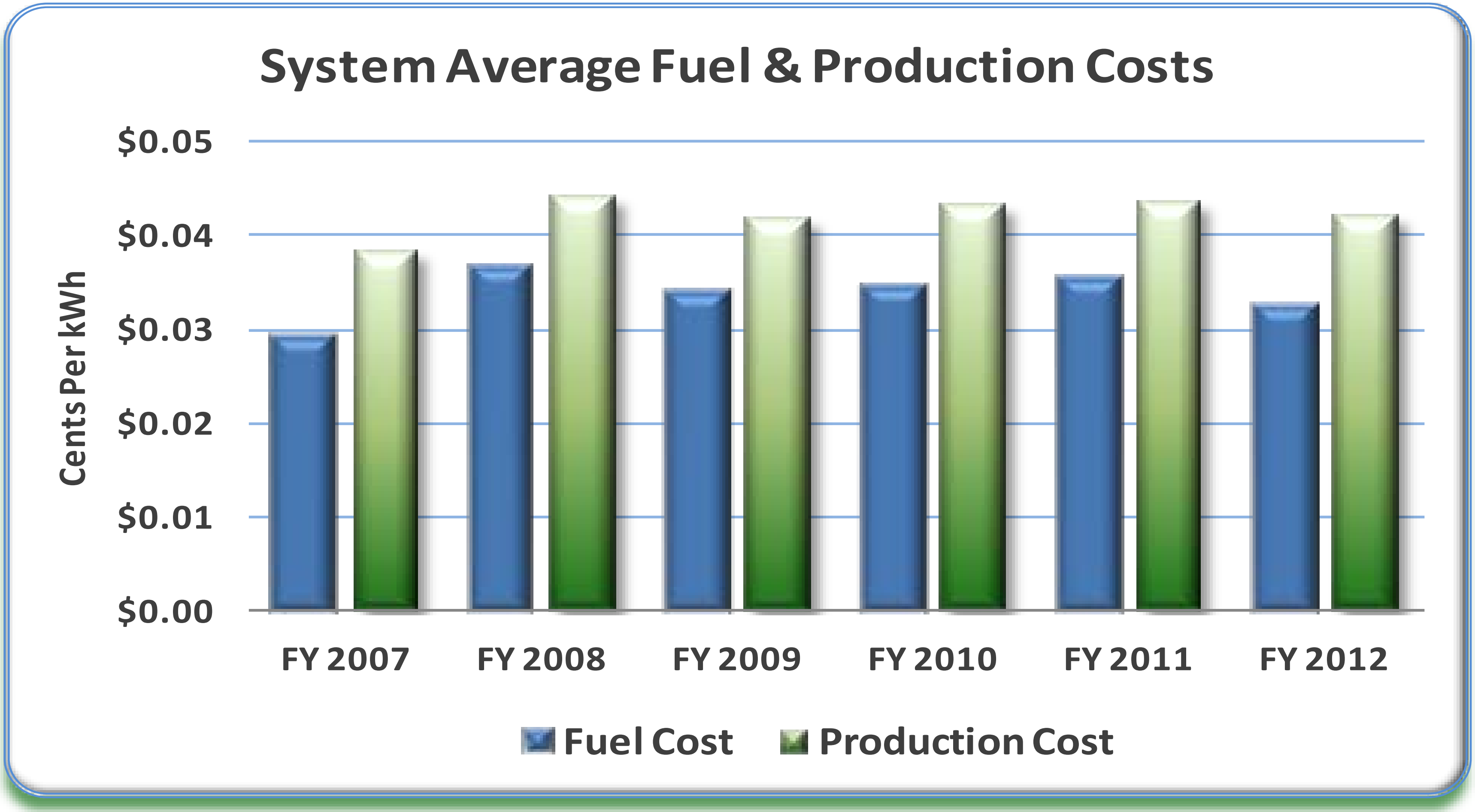
Measure	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
System annual average fuel cost (fuel/kWh)	3.655 cents per kWh	3.371 cents per kWh	3.446 cents per kWh	3.523 cents per kWh	3.225 cents per kWh

- Austin Energy's system annual average production cost is total operations and maintenance costs divided by total generation in kilowatt hours.

Table 47: System Production Cost

Measure	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
System annual average production cost (includes fuel plus operating & maintenance)	4.403 cents per kwh	4.165 cents per kwh	4.331 cents per kwh	4.304 cents per kWh	4.197 cents per kWh

Historical Average Fuel & Production Costs



Historical Fuel Costs by Type

- Costs allowed in the fuel tariff include commodity, purchase power, and ERCOT-related charges.

Table 38: Fuel Costs

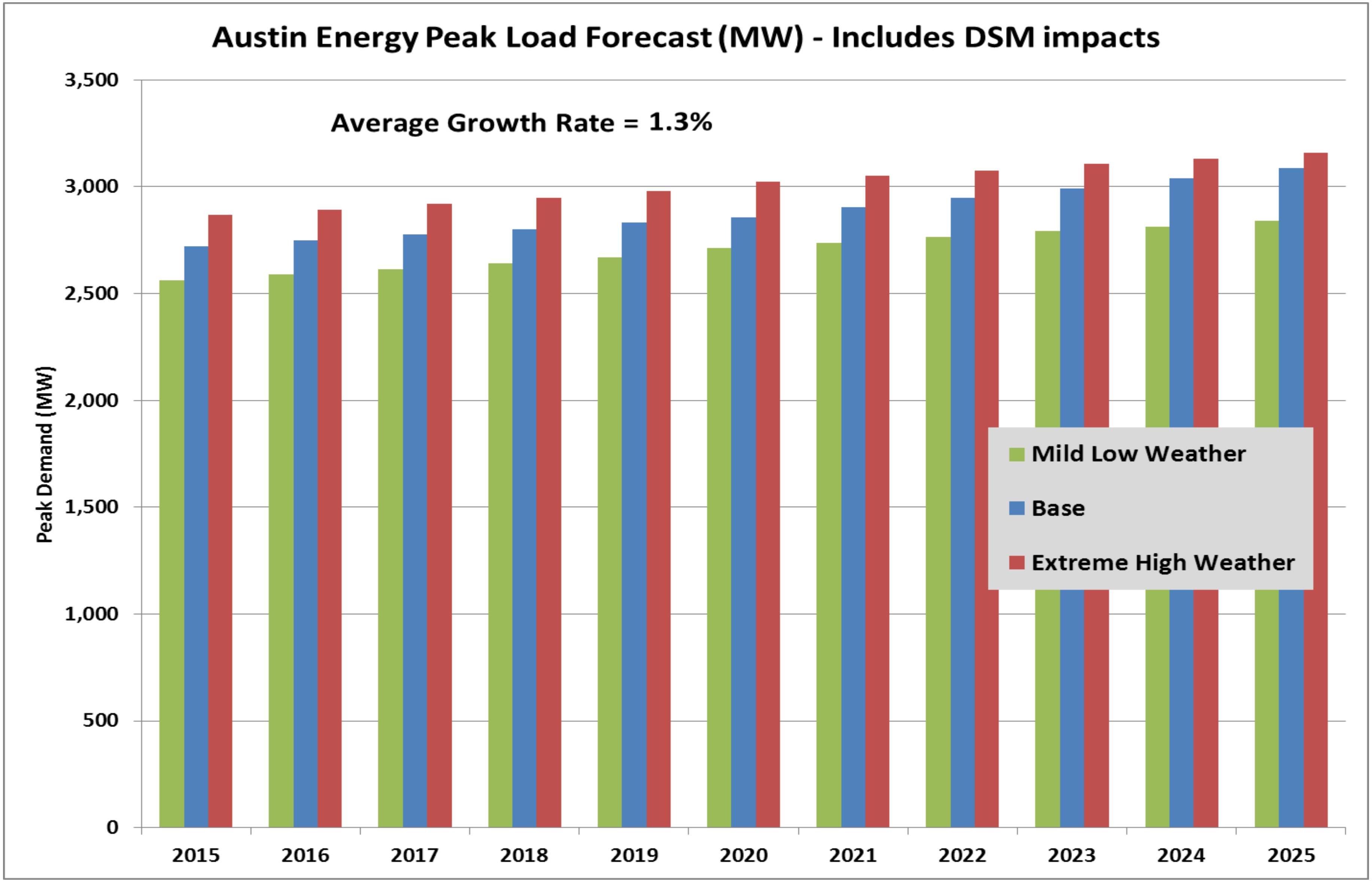
Fuel Cost	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Gas	$250,721,680	$214,711,985	$203,976,741	$190,320,211	$148,047,838
Coal	$87,063,860	$84,635,000	$91,590,706	$88,068,421	$85,032,243
Nuclear	$15,823,059	$16,866,183	$16,655,851	$18,295,747	$14,087,793
Fuel Oil	$420,142	$566,981	$2,405,166	$2,698,718	$897,703
Purchase Power	$90,621,318	$54,863,996	$53,409,677	$57,820,582	$10,831,546
ERCOT*	$10,165,180	$21,889,298	$21,617,196	$66,372,518	$69,831,165
Renewable	$26,183,662	$49,567,759	$48,631,116	$48,212,653	$97,167,511
Total	**$480,998,901**	**$443,101,202**	**$438,286,453**	**$471,788,849**	**$425,895,800**

*Through FY12, the ERCOT line item includes fees and charges from ERCOT such as net power costs and administrative and nodal fees. Beginning in FY13, those administrative and nodal fees associated with power supply adjustment customers are recovered through the regulatory charge.

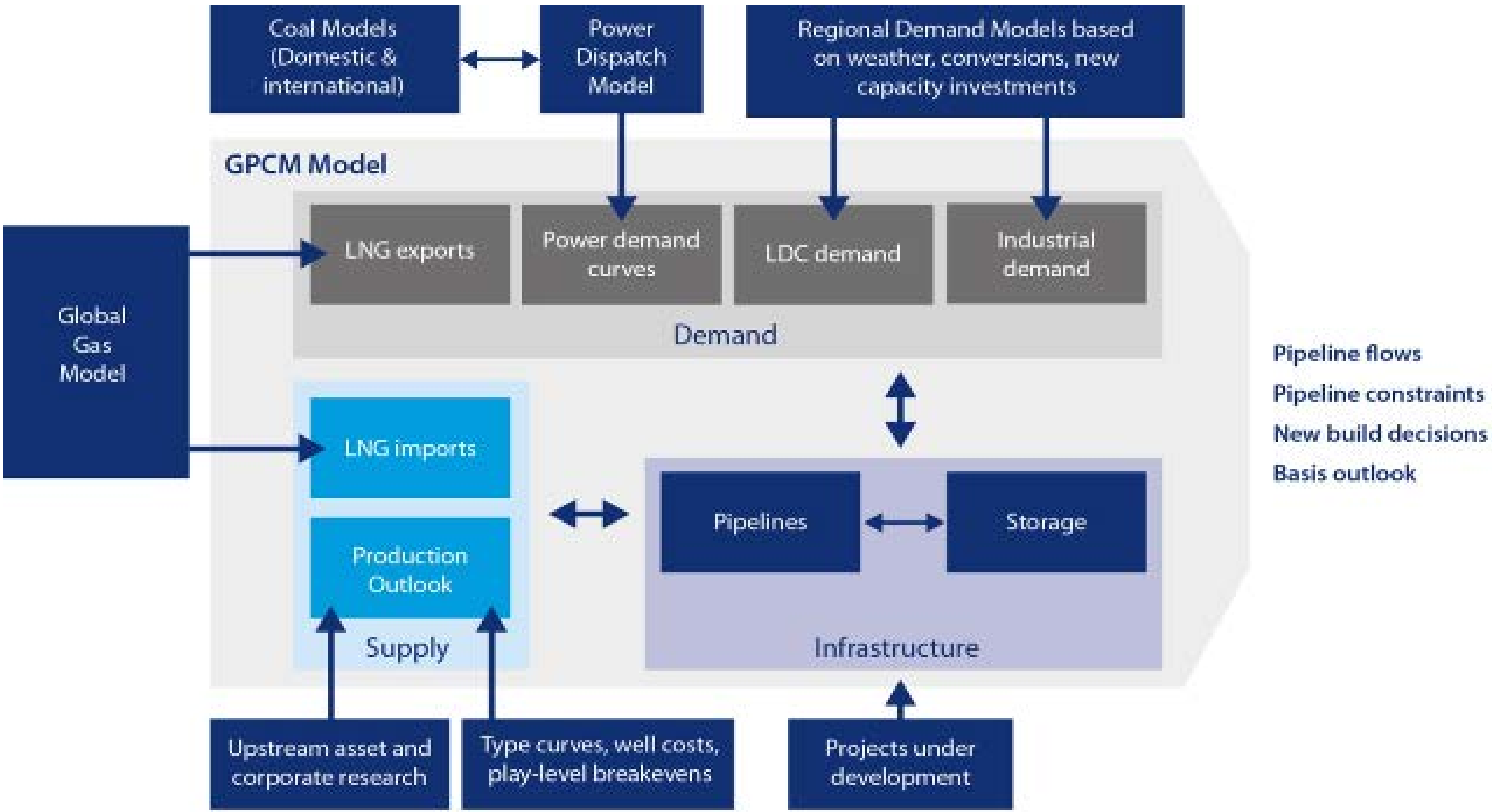
Regulations AE is Tracking

Rule	Potential Impacts
Lower ozone standard	Austin-area non-attainment and NOx control expense at local plants
CO_2 limits on existing and new power plants	No new coal construction plus additional generation costs based on CO_2 emissions intensity
Cooling water intake design standards	Possible upgrades to water intakes at FPP and Decker
Mercury limits on coal plants	Project under way to upgrade pollution controls at FPP to reduce mercury emissions
Cap and Trade for NOx and SO_2	Additional generation costs if allowance purchases needed

AE Peak Load Forecast



Wood Mackenzie Natural Gas Forecast Model



Source: Wood Mackenzie

High/Low Forecast Assumptions

Scenario variables

Supply-side variables	Demand-side variables

Supply-side variables

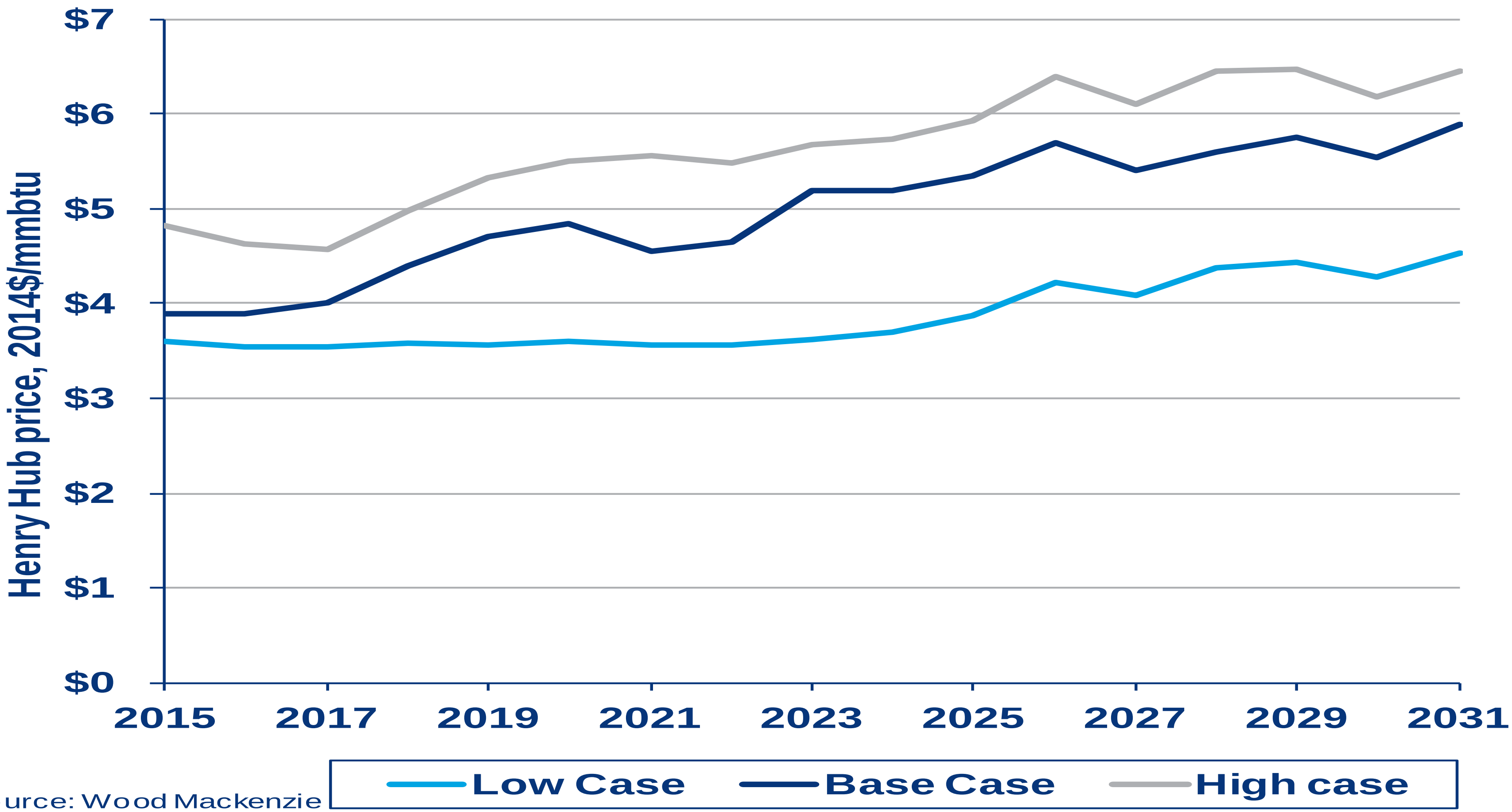
- Components of development cost
  - Rig efficiency and well productivity
  - Component cost inflation
    - Labor
    - Materials
    - Contracting
- Geological considerations
  - Core saturation rates
  - Lower tier play productivity
- Major policy variables
  - Hydraulic fracturing regulations and restrictions
  - Air quality regulations
  - Taxation regimes

Demand-side variables

- GDP growth rate
  - Electric load growth
  - Industrial production capacity
- Technology assumptions
  - Generation technology costs
  - Residential/commercial energy efficiency trends
- LNG exports
- Major policy variables
  - Renewable electricity generation support
  - Nuclear energy support/opposition
  - Carbon pricing

Wood Mackenzie

Fuel Price Forecasts (Preliminary)



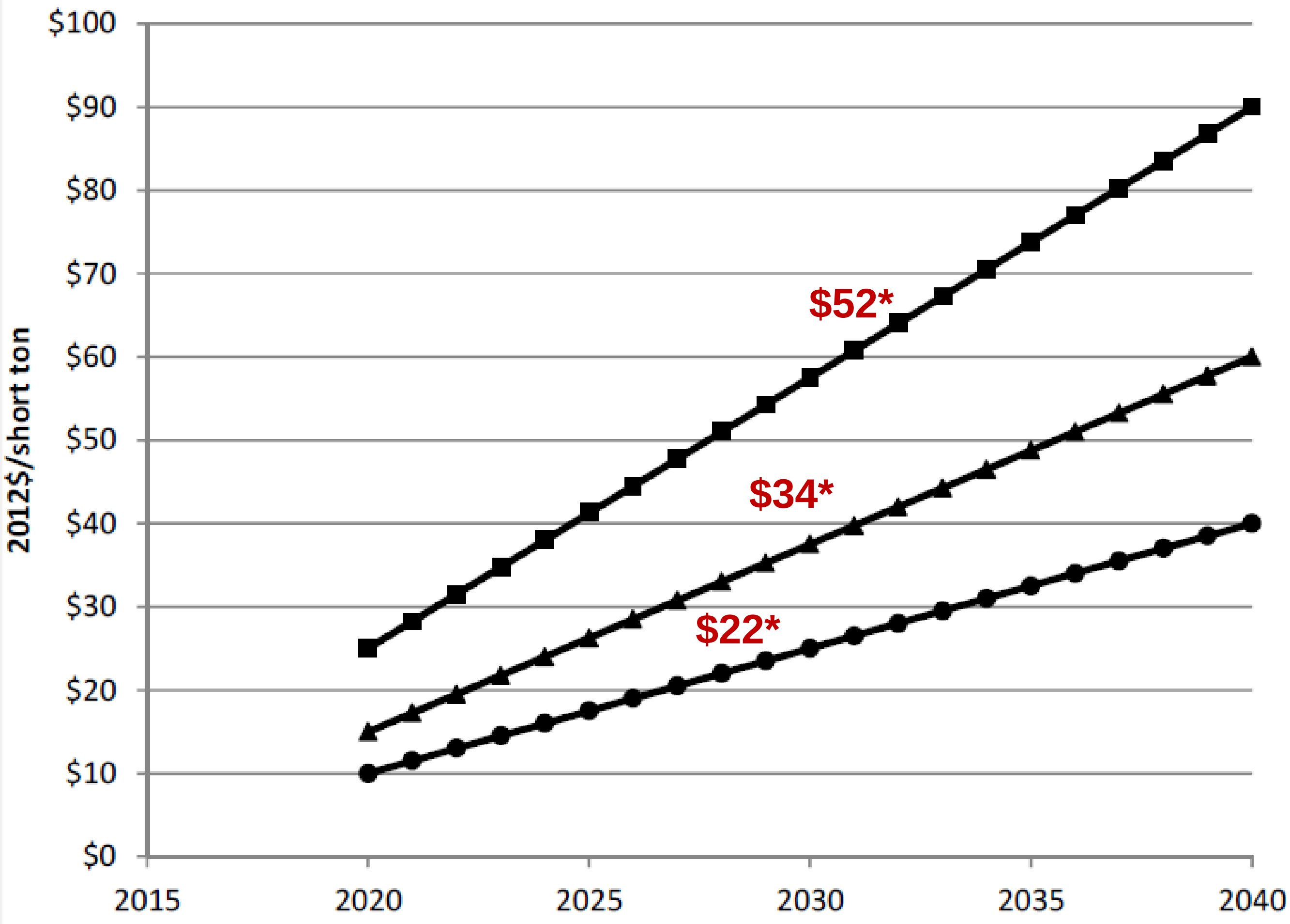
Source: Wood Mackenzie

- First 2 years will be replaced by NYMEX futures.

Environmental Assumptions

- ERCOT 2014 Long Term System Assessment (LTSA) Report
- Source: Synapse Energy Economics
  - Eventual Federal Cap and Trade due to regional and state inconsistency
  - Emission abatement cost per Energy Modeling Forum (EMF) research
  - Forecast range from 28 utility IRPs

ES- 1: Synapse 2013 CO_2 Price Trajectories



* 2020-2040 Levelized Price

New Generation/DSM Technology Costs

Estimated 30 Year Levelized Cost of New Dispatchable Resources, 2015 ($/MWh)

Plant type Dispatchable Technologies	*Average Capacity Factor (%)*	*Fuel Type*	*Overnight Capital Cost 2014$ ($/KW)*	*Heat Rate Btu/kWh*	*Base* *Levelized Capital Cost*	*Base* *Levelized O&M*	*Base* *Levelized Fuel*	*Base* *Levelized Total*	*Low*	*High*
Advanced Coal	85%	Coal	3,059	8,800	55.23	10.83	27.39	102.79	92.83	114.00
Advanced Nuclear	85%	Uranium	5,765	10,000	104.09	18.35	7.47	129.91	116.92	155.89
Biomass	85%	Wood Waste	3,002	13,500	54.21	24.32	49.81	128.33	102.67	154.00
Geothermal	50%	Heat	3,183	N/A	97.70	28.56	0.00	126.26	101.01	151.51
Natural Gas-Fired										
Advanced Combined Cycle	55%	Natural Gas	1,066	6,430	29.76	8.08	32.15	69.99	61.53	91.38
Advanced Combustion Turbine	10%	Natural Gas	705	9,750	108.16	23.02	48.75	179.93	167.10	212.36
Combined Heat/Power (CHP)	85%	Natural Gas	2,133	6,430	44.64	12.12	32.15	88.91	74.39	97.44
Compressed Air Energy Storage (CAES)	40%	Gas/Air	1,000	4,300	38.37	32.72	21.50	92.59	76.27	111.11
Fuel Cell	85%	Natural Gas	7,410	9,500	133.79	53.78	47.50	235.08	207.07	268.09

Estimated 30 Year Levelized Cost of New Non-Dispatchable Resources, 2015 ($/MWh)

Plant type Non-Dispatchable Technologies	*Average Capacity Factor (%)*	*Fuel Type*	*Overnight Capital Cost 2014$ ($/KW)*	*Heat Rate Btu/kWh*	*Base* *Levelized Capital Cost*	*Base* *Levelized O&M*	*Base* *Levelized Fuel*	*Base* *Levelized Total (Base)*	*Low*	*High*
Onshore Wind (West Texas)	40%	Wind	See Note 1	N/A	27.94	7.06	0.00	36.75	26.25	61.55
Onshore Wind (South Texas)	30%	Sun	See Note 1	N/A	30.59	9.41	0.00	44.00	36.00	75.41
Photovoltaic (>50 MW West Texas)	30%	Sun	See Note 1	N/A	46.38	5.88	0.00	52.26	45.00	114.23
Photovoltaic (<20 MW Local)	20%	Sun	See Note 1	N/A	93.10	19.81	0.00	112.91	90.33	213.30
Solar Thermal	50%	Sun	3,697	N/A	141.87	24.01	0.00	165.88	132.70	199.06
Demand-Side	30%	N/A	See Note 1	N/A	70.00	0.00	0.00	70.00	56.00	84.00

Notes:

(1) Source of Technology Cost per Energy Information Administration (EIA) April 2013 Update, except:

- Demand-Side Management per AE estimates

- Wind and Photovoltaic per AE estimates (Range includes & excludes Tax Credit)

- CAES per AE estimates within ERCOT

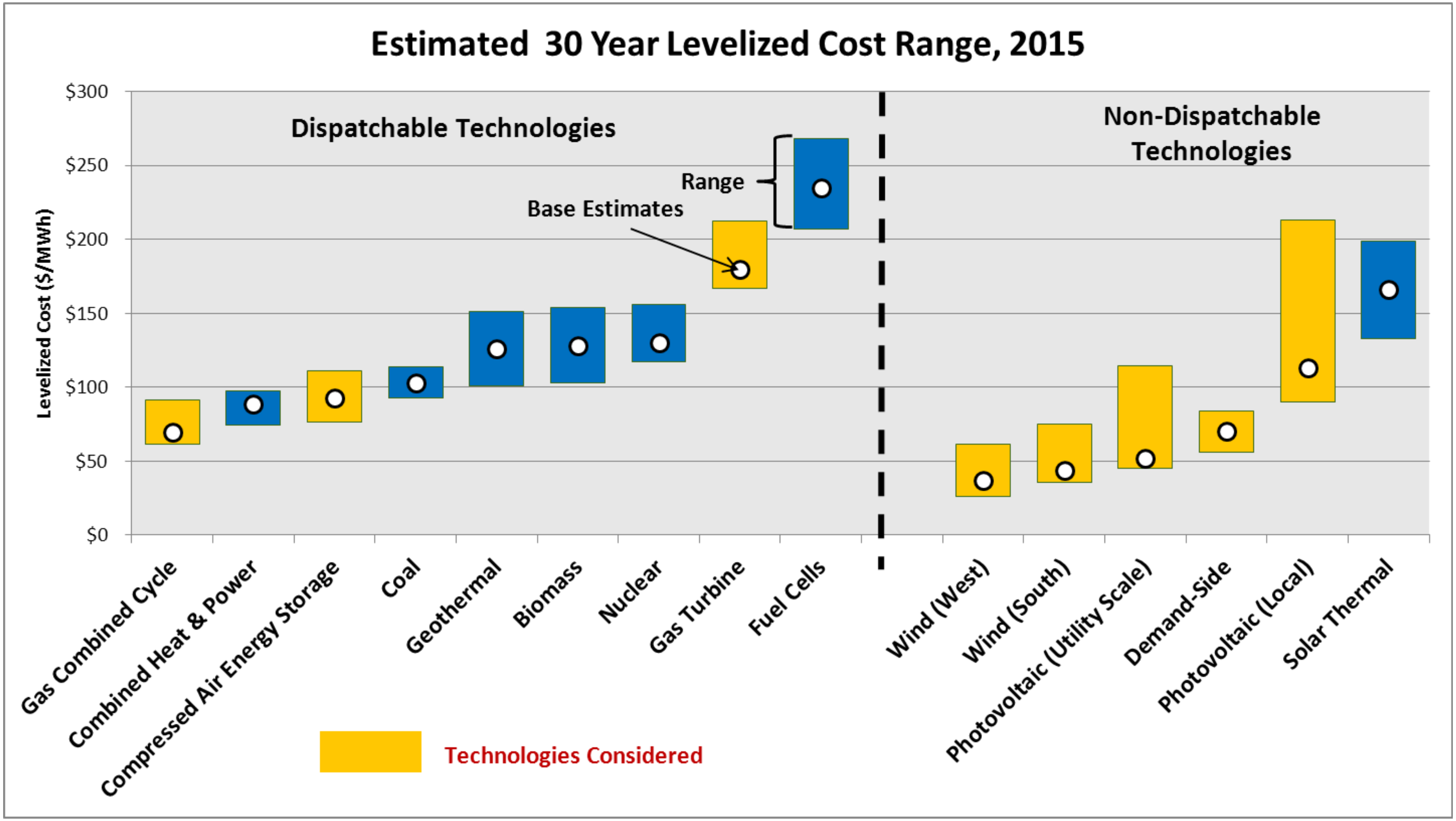
(2) Levelized capital cost estimates assumes 50% Debt / 50% Equity, 35% tax rate, Nominal After-Tax Weighted Cost of Capital (WACC) of 10.00%, 30-yr book life

(3) Low and High estimates includes emission cost of $12 to $25 per metric ton for annual CO2 emissions, if applicable to technology

(4) Natural Gas Price $5.00 per Mbtu, low $3.00 - high $7.00 per Mbtu, Coal Price $2.50 per Mbtu escalating 2.5% per year, Uranium price $0.6 escalating 2.5% per year, Biomass $40 per MWh escalating 2.5%, All others +/- 20%

(5) Non-indicative bid Renewable Technologies (i.e. Solar Thermal, Biomass, Geothermal) assumes tax credit

New Generation/DSM Technology Costs



Summary of Proposed Scenarios Representing Most Feedback from the Stakeholders

		Potential Scenarios							
				Increase Goals			Replace FPP & Decker		
		Least Cost Plan Meeting Council Goals	No Additional Generation	1000 MW of DSM with 40% Renewables by 2020	1200 MW of DSM with 50% Renewables by 2025	100% Emission Free by 2025	With Renewables + Natural Gas Simple Cycle Peakers	With Renewables + Natural Gas Combined Cycle	With Renewables + Compressed Air Energy Storage
Key Uncertainties (Relative to Current Forecasts)	High Gas								
	Low Gas								
	High Load								
	Low Load								
	High Carbon								
	Low Carbon								
	Capacity Market								
	PTC/ITC Extn								

- Scenarios cover a wide range of values for key uncertainties

List of Scenarios

Plan	Description
	Scenario 1 - Least Cost Plan Meeting Council Goals
SC1-1	Reduce FPP, 800 MW DSM, 35% Renewable, 200 MW PV (100 MW Local) 2020
SC1-4	SC1-1, Add GT & CCs
	Scenario 2 - No Additional Generation
SC2-1	Current System, No New Additions, PPAs Expire Per Term
	Scenario 3 -1000 MW of DSM and/or 40% Renewables by 2020
SC3-1	SC1-1, 40% Renewables by 2020, Optimized Wind & PV
SC3-2	SC3-1, Add GT & CCs
SC3-3	SC1-1, 1000 MW DSM, 40% Renewables by 2020, Optimized Wind & PV
SC3-4	SC3-3, Add GT & CCs
	Scenario 4 - 1200 MW of DSM and/or 50% Renewables by 2025
SC4-1	SC1-1, 50% Renewables by 2020, Optimized Wind & PV
SC4-2	SC4-1, Add GT & CCs
SC4-3	SC1-1, 1200 MW DSM, 50% Renewables by 2020, Optimized Wind & PV
SC4-4	SC4-3, Add GT & CCs
	Scenario 5 - 100% Emission Free by 2025
SC5-1	SC1-1, Retire FPP and All Gas Units by 2025
SC5-2	SC3-1, Retire FPP and All Gas Units by 2025
SC5-3	SC4-1, Retire FPP and All Gas Units by 2025
SC5-4	SC3-3, Retire FPP and All Gas Units by 2025
SC5-5	SC4-3, Retire FPP and All Gas Units by 2025
SC5-6	SC5-1, Replace Retirements with Optimized Wind & PV
	Scenario 6 - Replace FPP & Decker with Renewables + Natural Gas Simple Cycle Peakers
	Scenario 7 - Replace FPP & Decker with Renewables + Natural Gas Combined Cycle
	Scenario 8 - Replace FPP & Decker with Renewables + Compressed Air Energy Storage
SC6-1	SC1-1, Retire FPP 2025
SC6-2	SC6-1, Replace with Optimized Wind & PV
SC6-3	SC6-1, Replace with Optimized Wind & PV & GT/CC
SC6-4	SC6-1, Replace with Optimized Wind & PV & CAES
SC6-5	SC1-1, Retire Decker 2018
SC6-6	SC6-5, Replace with Optimized Wind & PV
SC6-7	SC6-5, Replace with Optimized Wind & PV & GT/CC
SC6-8	SC6-5, Replace with Optimized Wind & PV & CAES
SC6-9	SC1-1, Retire FPP 2025 and Decker 2018
SC6-10	SC6-9, Replace with Optimized Wind & PV
SC6-11	SC6-9, Replace with Optimized Wind & PV & GT/CC
SC6-12	SC6-9, Replace with Optimized Wind & PV & CAES
SC6-13	SC6-9, Replace with Optimized Wind & PV & GT/CC & CAES

- 8 Broad Scenarios
- 30+ Base plans
- 210+ Sensitivities

Financial and Economic Assumptions

- Capital
  - 30 year 80% debt financing
  - 5% interest rate (near term: 5 years)
  - 5.5% interest rate (beyond year 6)
  - Applies to CIP for current plants

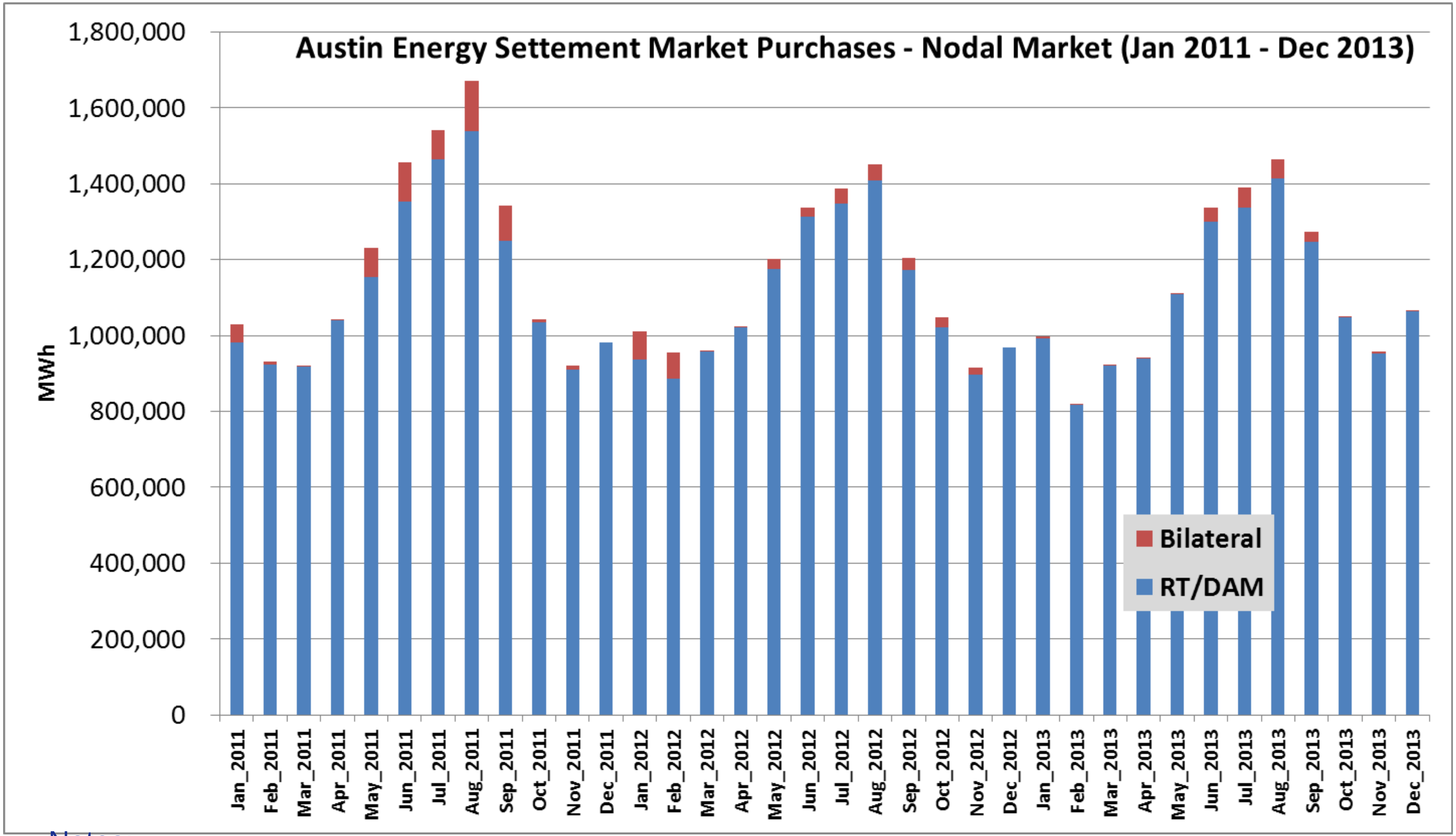
- Economic parameters
  - General inflation @ 2-3%
  - Discount Rate @ 5-12%

Evaluation Criteria and Scorecard (Preliminary)

- Metrics
  - Net Present Value (NPV$)
  - Rate of Return
  - Relative average rate Impact
    - Short term (3-5 years)
    - Long term (10 years)
  - Cost at risk (NPV$ uncertainty range)
  - Environmental (includes Carbon, Water etc.)

Scenario	NPV$	Rate of Return	Near term Avg. Rate	Long term Avg. Rate	Cost at Risk NPV$	Environmental
Do Nothing						
Least Cost						
Incr. Ren. Goals						

Nodal Market Purchases



Notes:

- Bilateral purchases are due to multiple factors including outages, risk management, and economics
- Specific purchases cannot be tied directly to a specific unit outage

Nodal Market Purchases

Month	RT/DAM Purchases	Bilateral Purchases	Total
Jan_2011	982,454	46,000	1,028,454
Feb_2011	923,551	6,400	929,951
Mar_2011	917,293	4,000	921,293
Apr_2011	1,039,270	1,600	1,040,870
May_2011	1,154,912	75,200	1,230,112
Jun_2011	1,353,181	103,200	1,456,381
Jul_2011	1,464,053	75,860	1,539,913
Aug_2011	1,538,980	132,200	1,671,180
Sep_2011	1,247,934	92,800	1,340,734
Oct_2011	1,035,352	6,400	1,041,752
Nov_2011	909,573	11,200	920,773
Dec_2011	981,366	0	981,366
Jan_2012	937,549	74,400	1,011,949
Feb_2012	886,590	69,600	956,190
Mar_2012	957,035	1,600	958,635
Apr_2012	1,021,513	3,200	1,024,713
May_2012	1,175,669	24,800	1,200,469
Jun_2012	1,313,214	24,000	1,337,214
Jul_2012	1,347,503	39,200	1,386,703
Aug_2012	1,407,894	41,600	1,449,494
Sep_2012	1,173,328	30,950	1,204,278
Oct_2012	1,020,652	26,456	1,047,108
Nov_2012	897,396	18,400	915,796
Dec_2012	966,926	0	966,926
Jan_2013	992,548	5,600	998,148
Feb_2013	818,125	1,200	819,325
Mar_2013	920,650	800	921,450
Apr_2013	939,671	800	940,471
May_2013	1,108,383	3,500	1,111,883
Jun_2013	1,300,091	36,000	1,336,091
Jul_2013	1,337,525	52,000	1,389,525
Aug_2013	1,413,634	49,600	1,463,234
Sep_2013	1,247,015	26,150	1,273,165
Oct_2013	1,048,425	1,375	1,049,800
Nov_2013	953,639	3,750	957,389
Dec_2013	1,062,856	800	1,063,656

Notes:
- Bilateral purchases are due to multiple factors including outages, risk management, and economics.
- Specific purchases are not tied directly to any specific unit outage