Appendix A-1

IRP Work Plan

CASCADE NATURAL GAS CORPORATION®
A Subsidiary of MDU Resources Group, Inc.

222 FAIRVIEW AVENUE N., SEATTLE WASHINGTON 98109-5312 206-624-3900
FACSIMILE 206-654-4039
www.cngc.com

December 14, 2009

Mr. David Danner, Executive Director & Secretary
Washington Utilities & Transportation Commission
P.O. Box 47250
Olympia, WA 98504-7250

RE: Cascade Natural Gas Corporation's 2010 Integrated Resource Plan Work Plan

Pursuant to WAC 480-90-238, enclosed for filing is Cascade Natural Gas Corporation's Work Plan for its 2010 Integrated Resource Plan (IRP or Plan). This document provides an outline of the content for the 2008 Plan, the timing of the plan development and the method for assessing potential resources.

If you have any questions regarding the Work Plan, please contact me at (206) 381-6824.

Sincerely,

Katherine J. Barnard

Katherine J. Barnard
Senior Director, Gas Supply & Regulatory Affairs

Enclosures

"In The Community To Serve"

Cascade Natural Gas Corporation
2010 IRP Work Plan

Cascade Natural Gas Corporation's ("Cascade" or "the Company") Work Plan for its 2010 Integrated Resource Plan ("IRP") is filed pursuant to the Washington Utilities and Transportation Commission (WUTC) IRP rules (WAC 480-90-238).

Purpose of the Integrated Resource Plan/Key Issues for 2010 IRP

The primary purpose of Cascade's long-term resource planning process has been, and continues to be, to inform and guide the Company's resource acquisition processes, consistent with the rule (WAC 480-90-238). Input and feed back from the Company's Technical Advisory Group (TAG) will continue to be an important resource to help ensure Cascade's IRP is developed from a broader perspective than Cascade could have on its own.

Analytical methods will be similar to those used to develop the Company's 2007 and 2008 IRPs, which includes the use of a linear programming optimization model (SENDOUT) to solve natural gas supply and transportation optimization questions, along with the use of Monte-Carlo simulations to estimate the impact of various uncertainty factors.

Outline of IRP Content:

The following is an outline of the Company's 2010 IRP plan. This list is based on the formats used in Cascade's 2008 IRP. Organizational structure of the final IRP may be revised based on results of analysis and feedback received through the planning process.

I. Executive Summary
II. Introduction & Planning Overview
III. Demand Forecast
IV. Distribution System Enhancements
V. Demand Side Resources
VI. Supply Side Resources
VII. Resource Integration
VIII. Two-Year Action Plan
IX. Appendices

2010 IRP Timeline

The following is Cascade's tentative 2010 IRP timeline:

- 2010 IRP Work Plan filed with WUTC: December 15, 2009
- Develop Demand Forecast: January through April 2010
- Distribution System Planning Analysis: March through June 2010
- Demand Side Resource Analysis: January through June 2010
- Gas Supply Analysis: January through June 2010
- Integration of Supply and Conservation Resources: June through July 2010
- Public Process: Technical Advisory Group Meetings (tentative dates)
    - TAG 1: Resource Alternatives (Supply/ Demand Side Resources) –February 4, 2010
    - TAG 2: Key Assumptions (Price Forecast & Economic Indicators) – March 18, 2010
    - TAG 3: Demand Forecast Results/Distribution System Planning/Preliminary Modeling of Conservation Supply Curves –April 27, 2010
    - TAG 4: Integration/ 2 year Action Plan –June 8, 2010
- File Draft 2010 IRP: July 31, 2010
- Public Process: TAG 5: Draft IRP Discussion –August 24, 2010

- Comments to Company on Draft Plan from parties due October 15, 2010
- Final 2010 IRP Filed: December 15, 2010

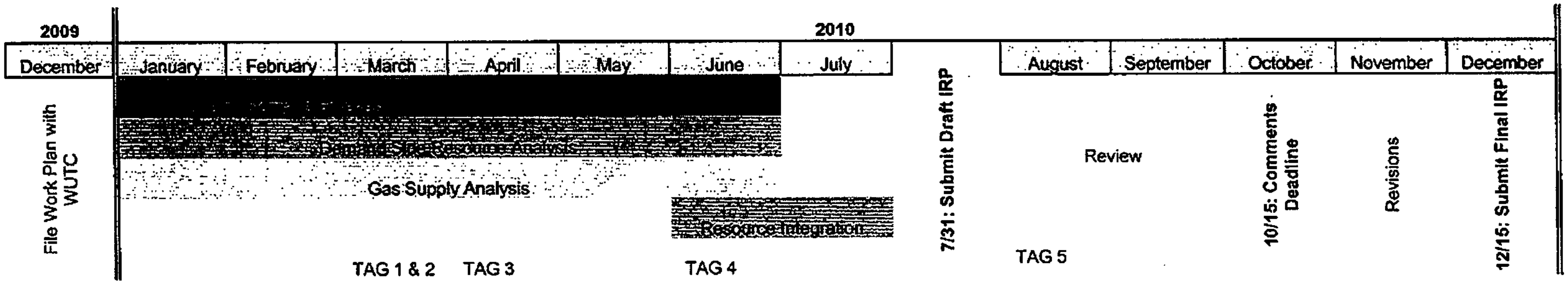
Planning Assumptions
Information needed to perform analysis will be gathered and input assumptions developed by May 2010. This will included detailed definitions of alternative scenarios and all primary input assumptions for demand forecasting and resource modeling. Additional planning information will be assimilated into the analytical process and planning information that is not incorporated into the modeling process will continue to be assessed.

Resource Analysis:
Natural gas analysis will include long-term optimization and stochastic analysis under the same planning scenarios, including natural gas energy efficiency and supply alternatives.

Draft 2010 IRP and Review Period:
Cascade is planning to have its IRP draft plan distributed for initial feedback to the group members by July 31, 2010. Given Cascade's commitment to facilitate and communicate with members of the Technical Advisory Group, the draft IRP content and its key assumptions will be discussed with the Technical Advisory Group during the TAG sessions. Any feedback is due to the Company by October 15, 2010 to give the Company sufficient time to incorporate such feedback as needed into the final plan.

Final 2010 IRP Filed December 15, 2010

Cascade Natural Gas Corporation
2010 IRP Timeline



2010 TAG Meetings

Meeting	Topic	Tentative Date	Tentative Location
TAG 1	Resource Alternatives (Supply & Demand Side Resources)	February 4, 2010	CNGC Seattle
TAG 2	Key Assumptions (Price Forecast & Economic Indicators)	March 18, 2010	CNGC Seattle
TAG 3	Demand Forecast Results & Preliminary Modeling for Conservation Supply Curves	April 27, 2010	CNGC Seattle
TAG 4	Integration/ 2 year Action Plan	June 8, 2010	CNGC Seattle
TAG 5	Draft IRP Discussion	August 24, 2010	Olympia

Appendix A-2

Tag Meeting Participants & Agendas

Cascade Natural Gas Corporation
Technical Advisory Group Meeting Participants

The following company and non-company individuals participated on one or more of the following Technical Advisory Group (TAG) meetings. The TAG meetings were held in February 2010, March 2010, April 2010, June 2010 and August, 2010.

Company Participants:

K Barnard	Manager Regulatory Affairs & Gas Supply
A. Spector	Manager- Conservation Programs
P. Schmidt	Supervisor, Regulatory Analysis
M. Sellers-Vaughn	Manager Supply Resource Planning
C. Robbins	Manager, Gas Supply
V. Duggirala	Rate and Conservation Analyst
M. Hardesty	Engineer

Non-Company Participants:

S. Johnson	Washington Utilities & Transportation Commission
D. Reynolds	Washington Utilities & Transportation Commission
V. Novak	Washington Utilities & Transportation Commission
P. Pyron	NW Industrial Gas Users
D. Kirschner	NW Gas Association
M. Clark	NW Gas Association
D. Dixon	NW Energy Coalition
C. Ebert	The Energy Project
M. Saldivar	Northwest Pipeline
J. Klingele	Consumer

2010 IRP Technical Advisory Group Meetings

February 4, 2010 Agenda Items

- 2010 IRP Workplan Overview
- Cascade System Overview
- Demand Side Resource Alternatives
- Supply Side Resource Alternatives

March 18, 2010 Agenda Item

- Demand Forecasting

April 27, 2010 Agenda Item

- Peak Day Planning
- Distribution System Planning
- Capacity Analysis
- Integration Modeling – Inputs & Preliminary Analysis

June 8, 2010 Agenda Item

- Review Conservation Objectives
- Washington Conservation Technical Potential Scenarios
- Carbon Legislation & Impact Scenarios
- Preliminary Conservation Curves

August 24, 2008 Agenda Items

- 2010 Workplan Update
- Price Forecast Update
- Preliminary Modeling Results
- Review Key Findings
- Avoided Cost Impacts

2010 Integrated Resource Plan

Technical Advisory Group Meeting
February 4, 2010

Agenda

- Introductions
- 2010 IRP Workplan Overview
- Cascade System Overview
- Demand Side (conservation) Resources
- Supply Side Resources
- Closing Discussion
  - Future meeting dates/Other Comments

Cascade's IRP Goals

- Provide reliable energy service while minimizing costs
- Provide the highest value to all Cascade stakeholders
- Consider resources both Conservation & Gas Supply on a consistent and comparable basis

IRP Strategies

- Maintain future decision flexibility while achieving an acceptable level of reliability and risk
- Consider avoidable distribution system costs in resource decision making
- Utilize the expertise and knowledge of the Staff and other interested parties to help achieve the Company's IRP goals

Planning Overview

- Develop a 20 year demand forecast (core)
- Analyze avoidable distribution system reinforcement costs
- Analyze potential resources
  - Demand Side Resources (conservation)
  - Supply Side Resources
- Integrate resources using a resource optimization model

2010 Public Process

- Technical Advisory Group (TAG) Meetings
  - Resource Alternatives (Feb 4, 2010)
    - Demand Side Resources (conservation)
    - Supply Side Resources
  - Key Assumptions (March 18, 2010)
  - Demand Forecast/Distribution System Planning/Preliminary Modeling of Conservation Supply Curves (April 27, 2010)
  - Integration/2 Year Action Plan (June 8, 2010)
  - Draft IRP Discussion (August 24, 2010)

Other important dates

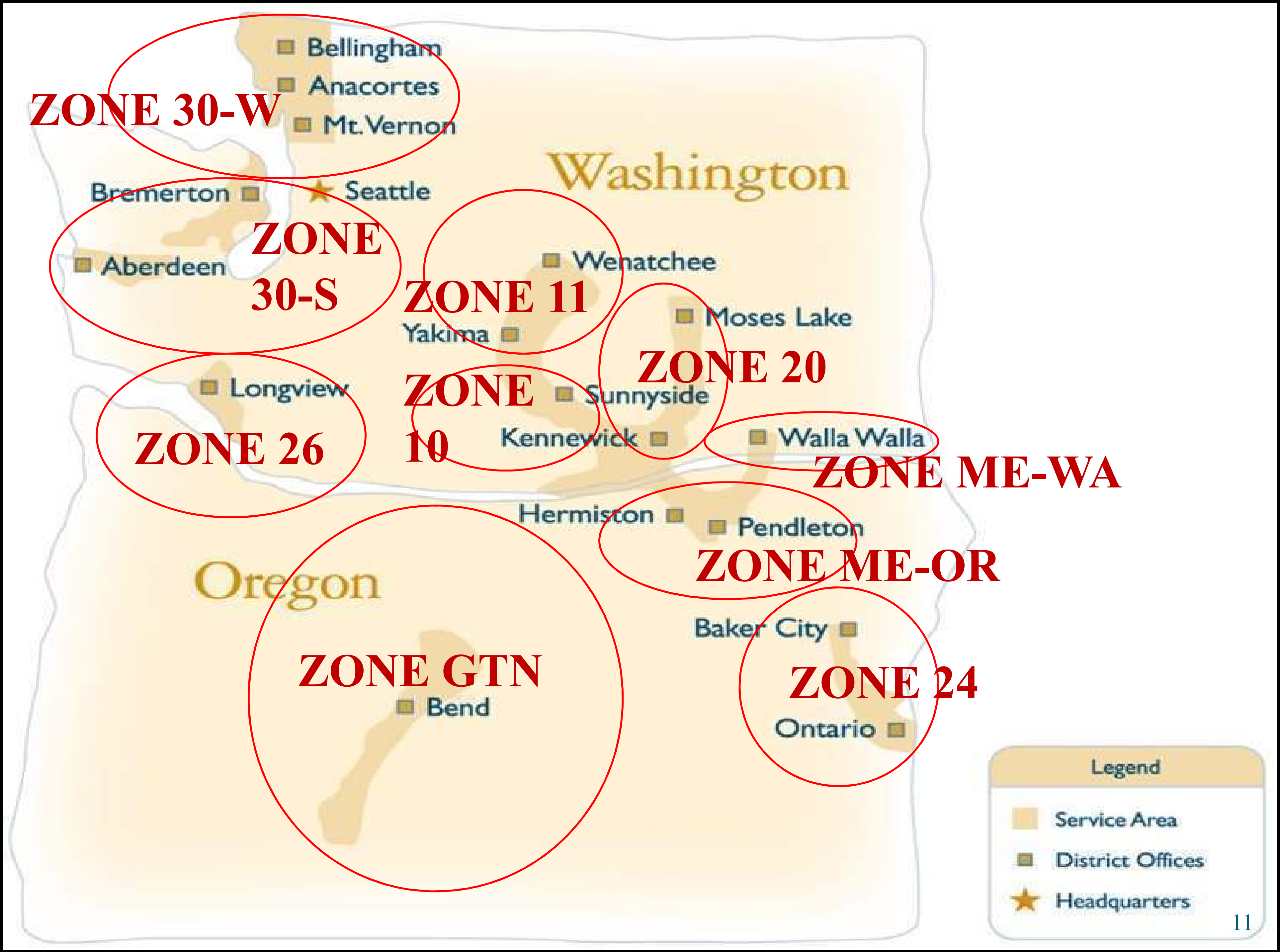
- File Draft 2010 IRP (July 24, 2010)
- Comments to Company on Draft Plan from parties due October 15, 2010
- Final 2010 IRP filed (December 15, 2010)

Cascade Natural Gas Overview


Bellingham
Anacortes
Mt. Vernon
Washington
Bremerton
Seattle
Aberdeen
Wenatchee
Moses Lake
Yakima
Longview
Sunnyside
Kennewick
Walla Walla
Hermiston
Pendleton
Oregon
Baker City
Bend
Ontario
Legend
Service Area
District Offices
Headquarters

Cascade System Overview

- Cascade Natural Gas Corporation is a natural gas local distribution company
- Provides service to customers in 93 communities throughout Washington and Oregon State.
- Cascade has approximately 251,200 customers.
- The company provides bundled natural gas service to approximately 218,000 residential, 32,500 small commercial and 500 small industrial customers.
- We provide unbundled distribution system only transportation service to approximately 200 large industrial and commercial transportation customers that accounts for up to 75% of the company's total throughput..



Bellingham
Anacortes
Mt. Vernon
ZONE 30-W
Washington
Bremerton
Seattle
ZONE 30-S
Aberdeen
Wenatchee
ZONE 11
Yakima
Moses Lake
ZONE 20
Longview
ZONE 10
Sunnyside
ZONE 26
Kennewick
Walla Walla
ZONE ME-WA
Hermiston
Pendleton
ZONE ME-OR
Oregon
Baker City
ZONE GTN
Bend
ZONE 24
Ontario
Legend
Service Area
District Offices
Headquarters

Overview of Demand Side Resources

Allison Spector

Director of Conservation

Agenda

- IRP DSM Action Plan Update
- Recent Program Developments
- DSM Analysis/Scenario Bundles
- Potential Technologies/Measures
- Measurement and Verification
- Discussion

IRP DSM Action Plan Update

- Continued development of WA Conservation Programs consistent with the steps outlined in the Company's 2007 Action Plan

- Continued monitoring of outside determinants of natural gas usage such as building code changes and electric lead "direct use" campaigns.

- Continued analysis of the Western Climate Initiative and other proposed state, regional, and federal carbon legislation.

- Planned development of "scenario bundles" to consider cost effective EE in context of increased gas costs associated with climate policy.

IRP DSM Action Plan Update

- Continued monitoring of cost-effectiveness for existing conservation measures with adjustments to portfolio as appropriate.

- Continued analysis of the cost-effectiveness of new/emerging technologies as well as those that may become cost effective in the near future.

- In 2009 shared proposed CIP updates to Conservation Advisory Group leading to significant changes to both Residential and Commercial portfolios.

- Attendance at multiple Washington WAP ramp-up forums to strengthen partnership and assist as leveraging partner with both DOE and ARRA funds.

Program Developments Since 2008 IRP

Residential

- Increased rebate for 90% furnace/PTCS duct sealing to $400
- Addition of $800 rebate for High Efficiency Combination Radiant heat systems
- Removal of Energy Star Clothes Washers and Tankless Water Heaters
- Increase of Wall Insulation to $.40/sf

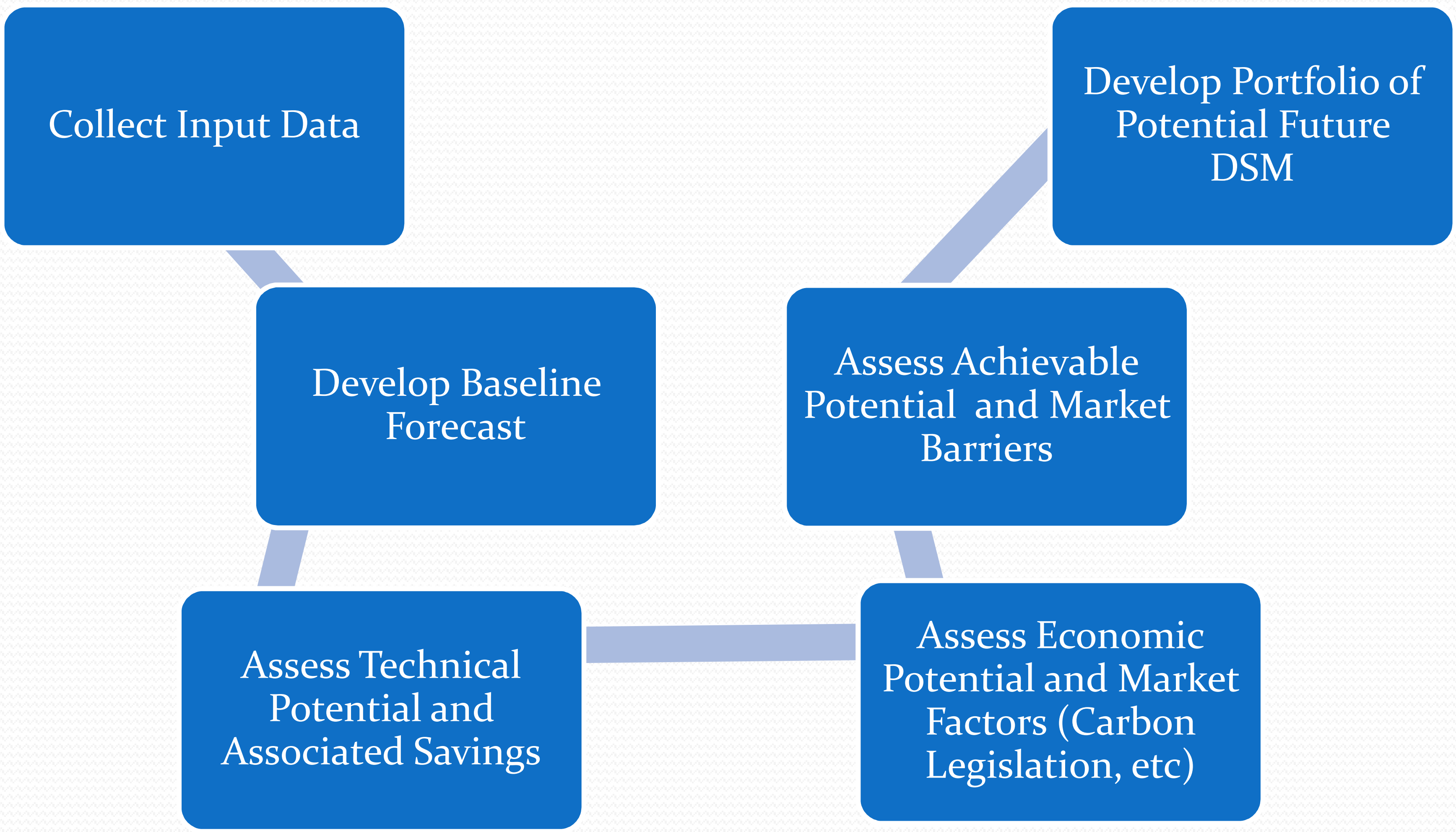
Commercial

- Addition of prescriptive tiers for insulation rebates
- Increase in boiler incentive to $4.00/kbtu/hr
- Addition of $80 rebate for boiler steam traps

Low Income

- Continued close partnership with the Low Income Weatherization Assistance Program.

Demand Side Management- Analysis Process



Baseline Development and Analysis of Potential from 2008 IRP

- **Technical Potential**
  - Quantified the current energy used by sector and customer type
  - Estimated energy consumption by end use for each customer type
  - Applied the forecasted growth rate to estimate the customer base available in future years
  - Reviewed information on specific measure for applicability to Cascade's customers

- **Deemed energy savings and associated costs**
  - Identified deemed savings and costs by climate zone
  - Provided technical and potential supply curve savings for Oregon (2028) and Washington (2028)

2010 IRP Scenario Bundles

- Considers Various Impacts on Cost of Natural Gas
- State, Federal and Regional Regulations
    - Cap and Trade
    - Change in Building Codes
    - Increased Demand for DSM Resources
    - Carbon Legislation

2010 Residential Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1 -$2.50/therm (post carbon world)	$2.50 and over/therm
Insulation Retrofits (retrofit all zones)	X			
E* with Heat Recovery Ventilators (new, zone 3)	X			
Duct Sealing & 90%+ AFUE Furnace (retrofit all zones)	X			
Duct Sealing & E* Insulation (new all zones)	X			
AFUE 90 Furnace (new all zones & retrofit zones 1&3)	X			
Duct Sealing (retrofit all zones)	X			
Boiler to Polaris Combo Radiant (retrofit zones 1 &3)	X			

2010 Residential Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
E* Dishwasher (new & retrofit, all zones)	X			
E* Plus (new. zones 1 &3)	X			
Combo with Hot Water Delivery (all zones, retrofit)	X			
High Efficiency Unit Heater (new and retrofit)	X			
E* Plus (FTC) Insulation (new, zone 2)		X		
90% AFUE Furnace (retrofit zone 2)		X		
E* Plus with Heat Recovery Ventilators (new, zones 2&1)		X		
New & Existing Tankless (new & retrofit all zones)			X	

2010 Residential Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
AFUE 85 DWH combo (retrofit all zones)			X	
Heat Recovery Ventilators (retrofit all zones)			X	
50 gal Gas Tank upgrades (new and retrofit)			X	
Solar Hot Water Heaters w/ Gas Back Up (new and retrofit, zone 2)				X
50 gal Condensing Gas Tank Upgrade (new and retrofit, all zones)				X

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
High Efficiency Clothes Washers (new and retrofit)	X			
Heat Reclaim w/ Floating Head Control (new and retrofit)	X			
E* Steam Cookers (new and retrofit)	X			
Wall Insulation (Blown R-11) (retrofit)	X			
Roof Insulation R0-R30, R0-19 (blanket), R0-30 (blanket), (retrofit)	X			
Infrared Fryers (new and retrofit)	X			
Solar Pool Heaters (new and retrofit)	X			

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
HW Boiler Tune (retrofit)	X			
Hot Water Temperature Reset (retrofit)	X			
Roof Insulation (Rigid R0-11, R0-22) (retrofit)	X			
Wall Insulation- Spray On for Metal Buildings (retrofit)	X			
Steam Balance (retrofit)	X			
Waste Water Heat Exchanger (new and retrofit)	X			
Direct Fired Convection Oven (new and retrofit)	X			

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
DHW Wrap (retrofit)	X			
High Efficiency unit Heather (new and retrofit)	X			
Wall Insulation- Spray On for Metal Buildings (retrofit)	X			
Steam Balance (retrofit)	X			
Waste Water Heat Exchanger (new and retrofit)	X			
Direct Fired Convection Oven (new and retrofit)	X			

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
DWH Showerheads/Faucets (retrofit)	X			
Roof Insulation (attic- R11-30) (rigid, R11-22) (roofcut R0-22) (retrofit)	X			
Computerized Water Heater Control (retrofit)	X			
Vent Damper (retrofit)	X			
Combo High Efficiency Boiler (new and retrofit)	X			
Warm-up Control (retrofit)	X			
Convection Range/Oven (new and retrofit)	X			

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
SPC High Efficiency Boiler (new and retrofit)	X			
Power Range Burner (new and retrofit)	X			
DCV (retrofit)	X			
Condensing Unit Heater from Nat Draft (new and retrofit)	X			
SPC Condensing Boiler (new and retrofit)	X			
DWH Condensing Tank (new and retrofit)	X			
Infrared Griddle (new)	X			

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
DWH Hi-efficiency boiler (new and retrofit)	X			
Combo Condensing Boiler (new and retrofit)	X			
Power Burner (retrofit)	X			
DWH Pipe Insulation (retrofit)	X			
Infrared Griddle (retrofit)		X		
DHW Recirculation Controls (retrofit)		X		
HVAC Controls (new)		X		
Duct Retrofit of Insulation and Air Sealing			X	

2010 Commercial/Industrial Bundles

Measure	Less than $.85/therm	$.85 to $1/therm	$1-$2.50/therm	$2.50 and over/therm
Computerized Water Heater Control (new)			X	
DWH Condensing Boiler (new and retrofit)			X	
Roof Insulation (Rigid R11033) (Blanket R11-R-30 & R11-41) (retrofit)			X	
Condensing Unit Heater from Power Draft (new and retrofit)			X	
Solar Hot Water (new and retrofit)			X	
Condensing Furnace (new and retrofit)			X	
Steam Trap Maintenance (retrofit)			X	
HVAC System Commissioning (new)			X	

Potential Technologies and Measures

- **Residential Measures**
  - Next generation conventional gas water heaters
  - Exploring Potential of condensing tankless water heaters
  - Gas Heat Pumps (monitoring as technology develops)

- **Commercial/Industrial Additional Measures**
  - Commercial Kitchen Measures
  - Continued strategic custom use of Refrigerant Heat Reclaim/Recovery
  - Solar Assisted Heat (if gas costs rise)

Measurement and Verification

- Plans to examine EE measures in place for full calendar year for preliminary assessment of actual versus deemed therm savings
- Sample of prescriptive measures and 100% of custom commercial
- Collaboration with Resource Conservation Managers (RCMs) partnering on conservation projects with CNGC

Questions and Discussion

Supply Side Resource Overview

Mark Sellers-Vaughn
Manager, Gas Supply Planning & Systems

SUPPLY AREAS

- Rocky Mountains
- Alberta
- British Columbia

SUPPLY

Firm, Diversified Supply Contracts Based on Warmer-than-Normal Weather

–Annual Supplies (some of these are previously entered contracts expiring over the next few years)

–Traditional Seasonal Supplies (November – March)

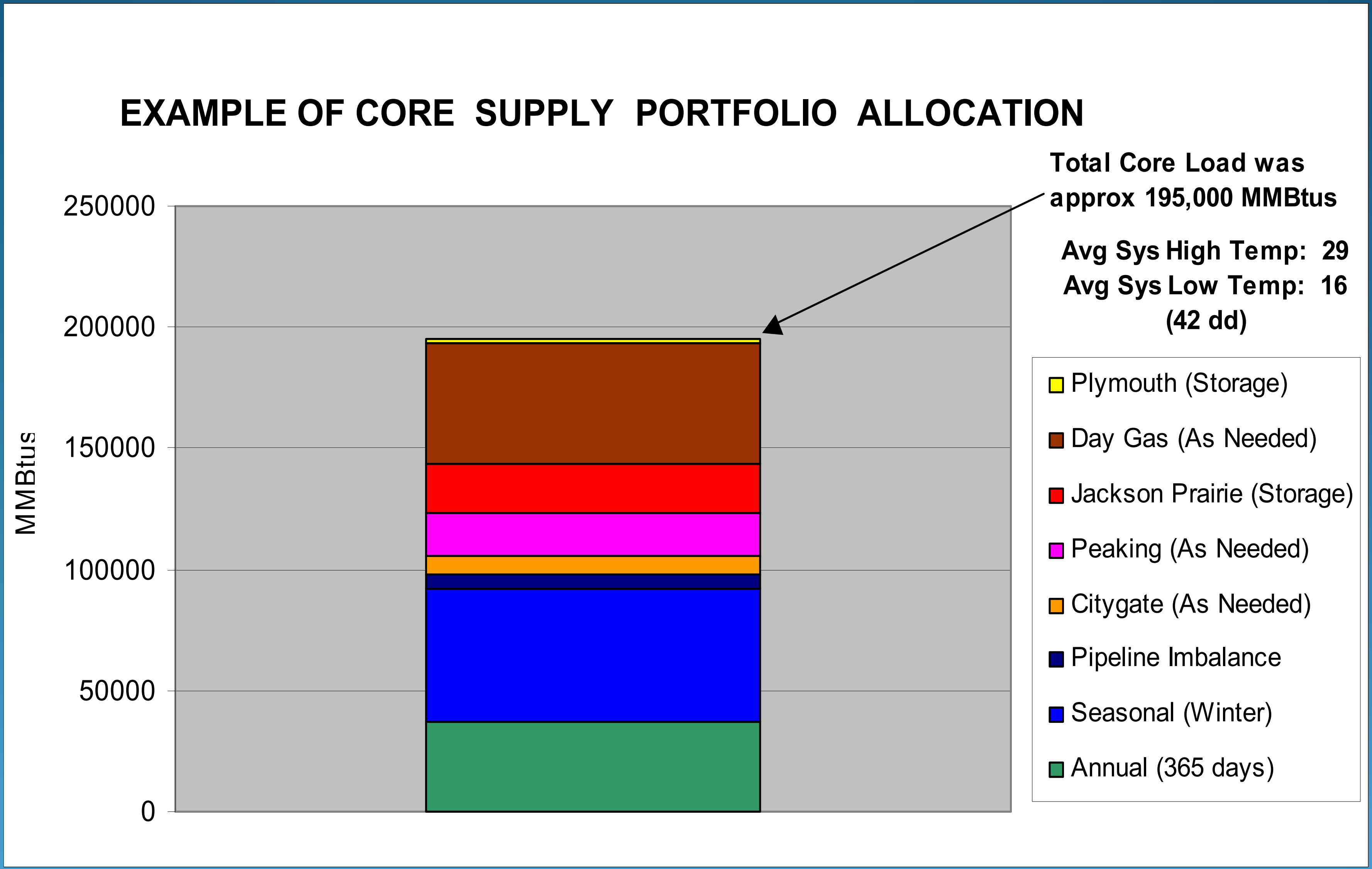
–Off-Seasonal Supplies (Spring, Summer, etc)

–First of Month (Spot, Just-in-time, Day Gas)

–City gate Deliveries

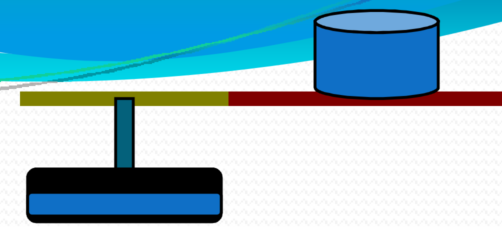
–Peaking Supplies

–Storage



EXAMPLE OF CORE SUPPLY PORTFOLIO ALLOCATION
Total Core Load was approx 195,000 MMBtus
Avg Sys High Temp: 29
Avg Sys Low Temp: 16
(42 dd)
MMBtus
250000
200000
150000
100000
50000
0
Plymouth (Storage)
Day Gas (As Needed)
Jackson Prairie (Storage)
Peaking (As Needed)
Citygate (As Needed)
Pipeline Imbalance
Seasonal (Winter)
Annual (365 days)

Storage



- Jackson Prairie #1
  - Seasonal Qty of 604,351 dths
  - Withdrawal capability 16,789 dths
  - Expires 10/31/2019
- Jackson Prairie #2
  - Seasonal Qty of 350,000 dths
  - Withdrawal capability 30,000 dths
  - Expires 10/31/2060
- Plymouth LNG
  - Seasonal Qty of 562,000 dths
  - Withdrawal capability of 60,000 dths
  - Expires 10/31/2019

Storage Management

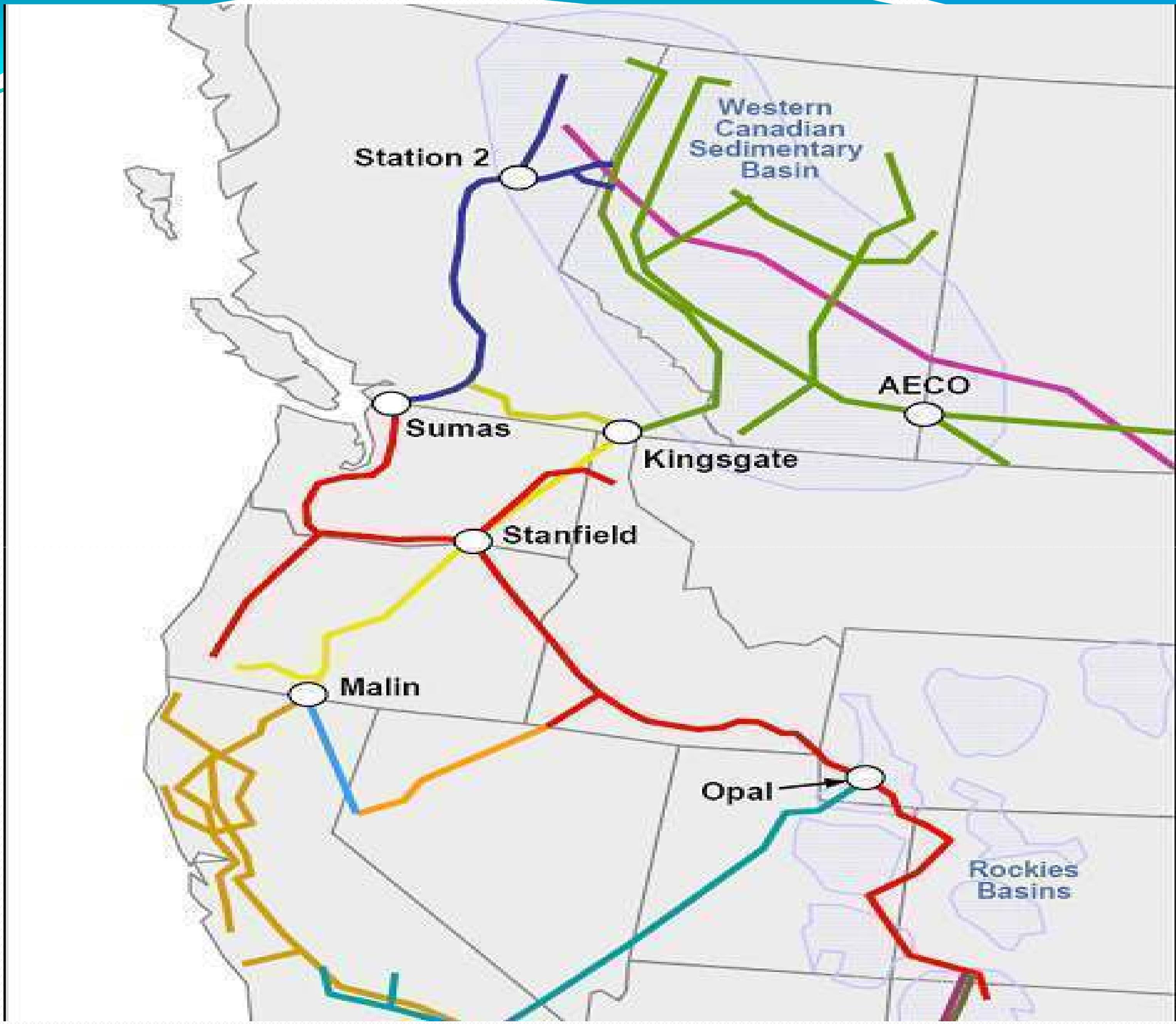
- We weigh storage usage versus Spot/Daily Supply Costs and operational conditions
- Typically CNG uses storage withdrawals in the winter and inject in the summer
- CNG allows others to manage our risk for a profit to the bottom line

CAPACITY RESOURCES

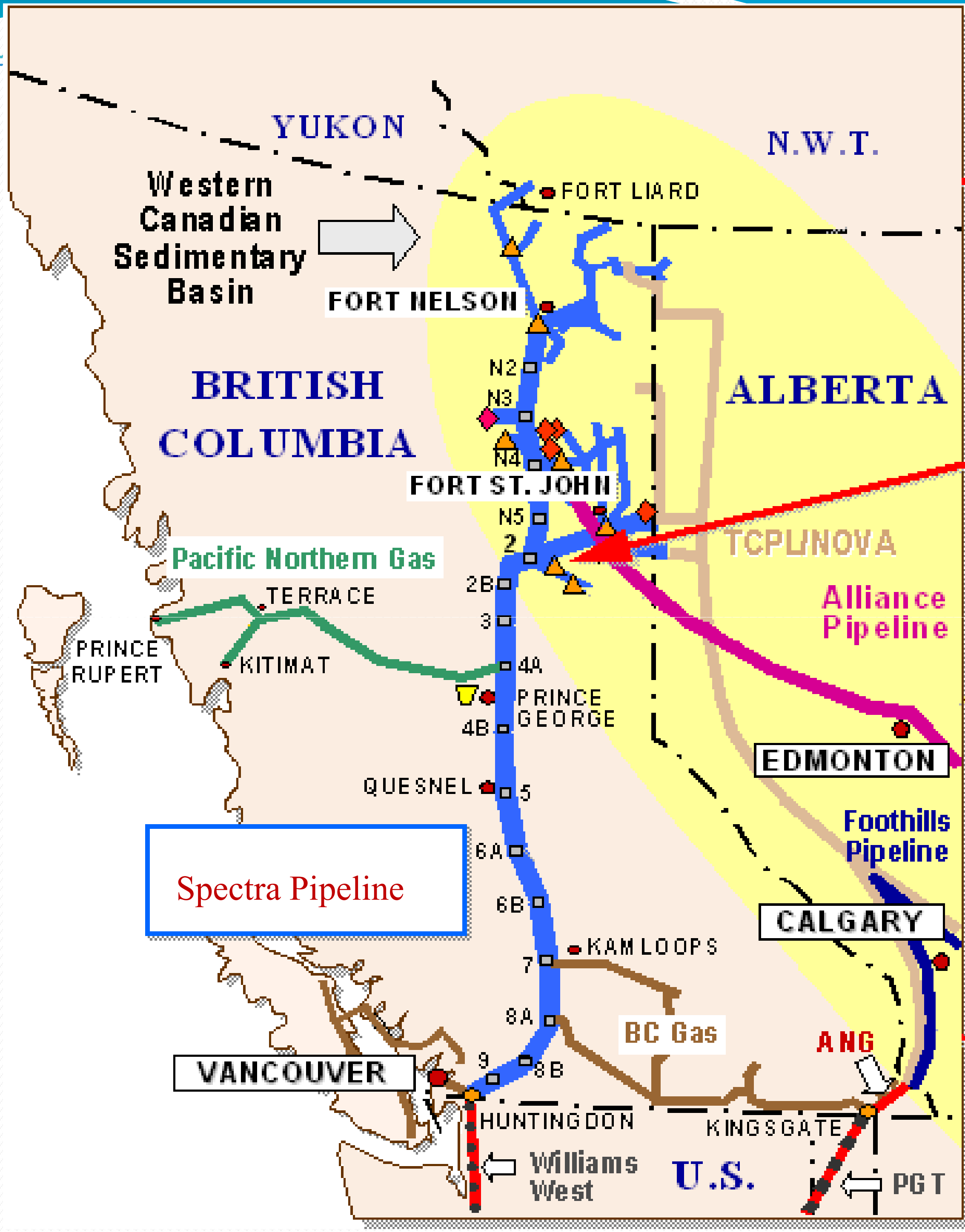
INTERSTATE PIPELINE TRANSPORTATION

- NORTHWEST PIPELINE
- SPECTRA ENERGY (WESTCOAST)
- GAS TRANSMISSION NORTHWEST (GTN)
- FOOTHILLS PIPELINE (ANG)
- NOVA (NGTL)

CAPACITY RELEASE ELECTRONIC BULLETIN BOARDS (EBB)


Western
Canadian
Sedimentary
Basin
Station 2
Sumas
Kingsgate
AECO
Stanfield
Malin
Opal
Rockies
Basins

Page 134



Page 135

Spectra Station 2 to Sumas 20,000 MMBtu/Day

Station 2

TCPL AECO to Kingsgate 23,400 MMBtu/Day

NWP – Sumas South:

120,732 MMBtu/Day

GTN – Kingsgate to Bend:
38,781 MMBtu/Day

-- Kingsgate to Malin

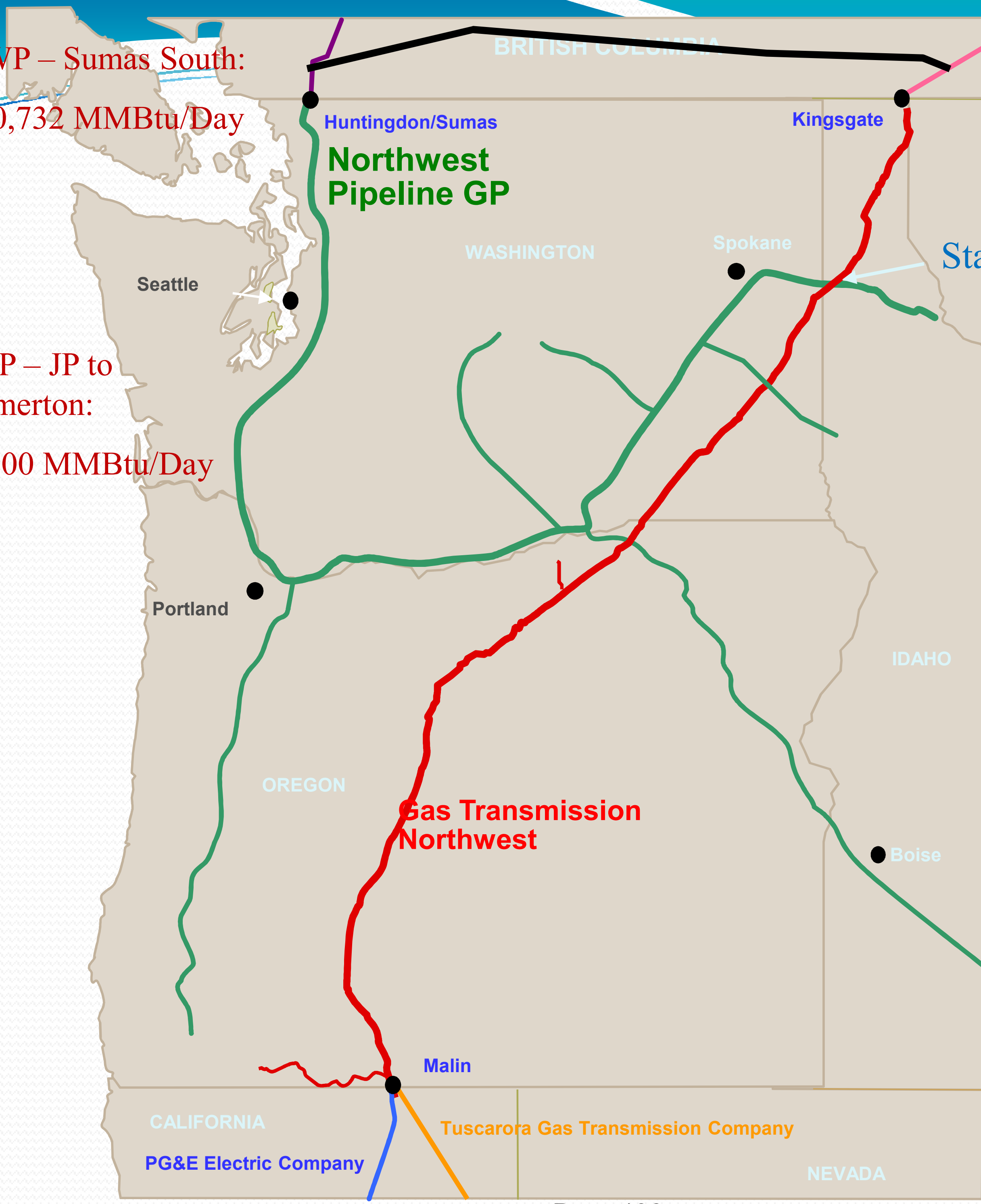
23,980 MMBtu/Day

Starr Road

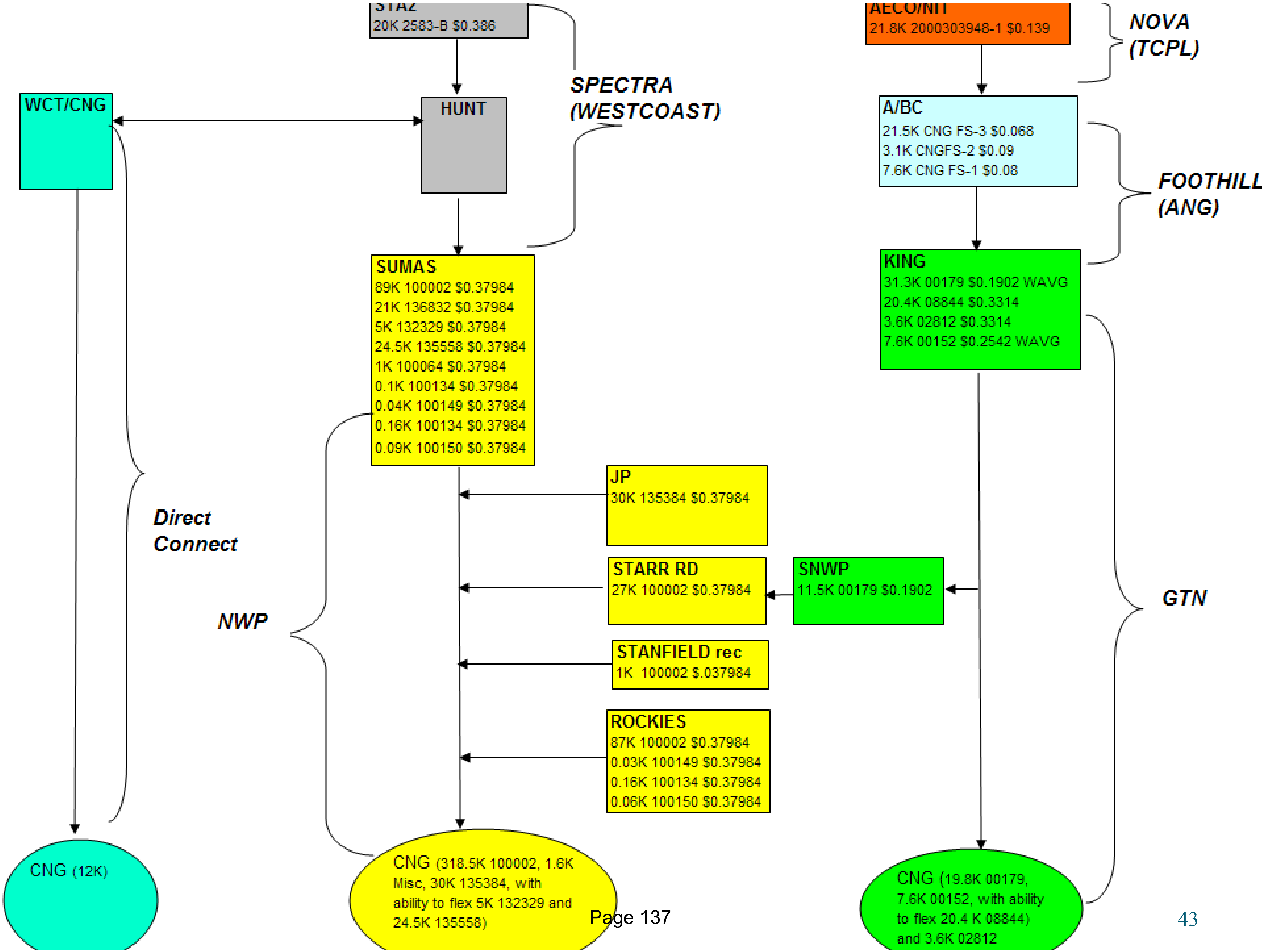
Williams – Starr Road :
27,055 MMBtu/Day

NWP – JP to
Bremerton:

30,000 MMBtu/Day



NWP – Rockies : 88,979
MMBtu/Day


STAZ
20K 2583-B $0.386
HUNT
SPECTRA (WESTCOAST)
WCT/CNG
AECO/NIT
21.8K 200303948-1 $0.139
NOVA (TCPL)
A/BC
21.5K CNG FS-3 $0.068
3.1K CNGFS-2 $0.09
7.6K CNG FS-1 $0.08
FOOTHILL (ANG)
SUMAS
89K 100002 $0.37984
21K 136832 $0.37984
5K 132329 $0.37984
24.5K 135558 $0.37984
1K 100064 $0.37984
0.1K 100134 $0.37984
0.04K 100149 $0.37984
0.16K 100134 $0.37984
0.09K 100150 $0.37984
KING
31.3K 00179 $0.1902 WAVG
20.4K 08844 $0.3314
3.6K 02812 $0.3314
7.6K 00152 $0.2542 WAVG
Direct Connect
JP
30K 135384 $0.37984
STARR RD
27K 100002 $0.37984
SNWP
11.5K 00179 $0.1902
GTN
NWP
STANFIELD rec
1K 100002 $.037984
ROCKIES
87K 100002 $0.37984
0.03K 100149 $0.37984
0.16K 100134 $0.37984
0.06K 100150 $0.37984
CNG (12K)
CNG (318.5K 100002, 1.6K Misc, 30K 135384, with ability to flex 5K 132329 and 24.5K 135558)
CNG (19.8K 00179, 7.6K 00152, with ability to flex 20.4 K 08844) and 3.6K 02812

SUPPPLY SIDE RESOURCE OPTIONS and UNCERTAINTIES

STORAGE OPTIONS

Short Range Possibilities

- NWN MIST
- ON-SITE LIQUIFIED NATURAL GAS (SATELLITE LNG)
- TRUCKED-IN LNG
- POST ID2 EXCHANGES ABOVE THE BORDER
- CLAY BASIN

STORAGE OPTIONS

Longer Range Possibilities:

- ACQUISTION OF AECO STORAGE
- PACIFIC NORTHWEST LNG
- CALIFORNIA STORAGE
- JACKSON PRAIRIE EXPANSION
- PARTNERING WITH OTHERS TO BUILD STORAGE FACILITY

Proposed LNG locations which should be considered

PROPOSED LNG TERMINALS AND PIPELINES

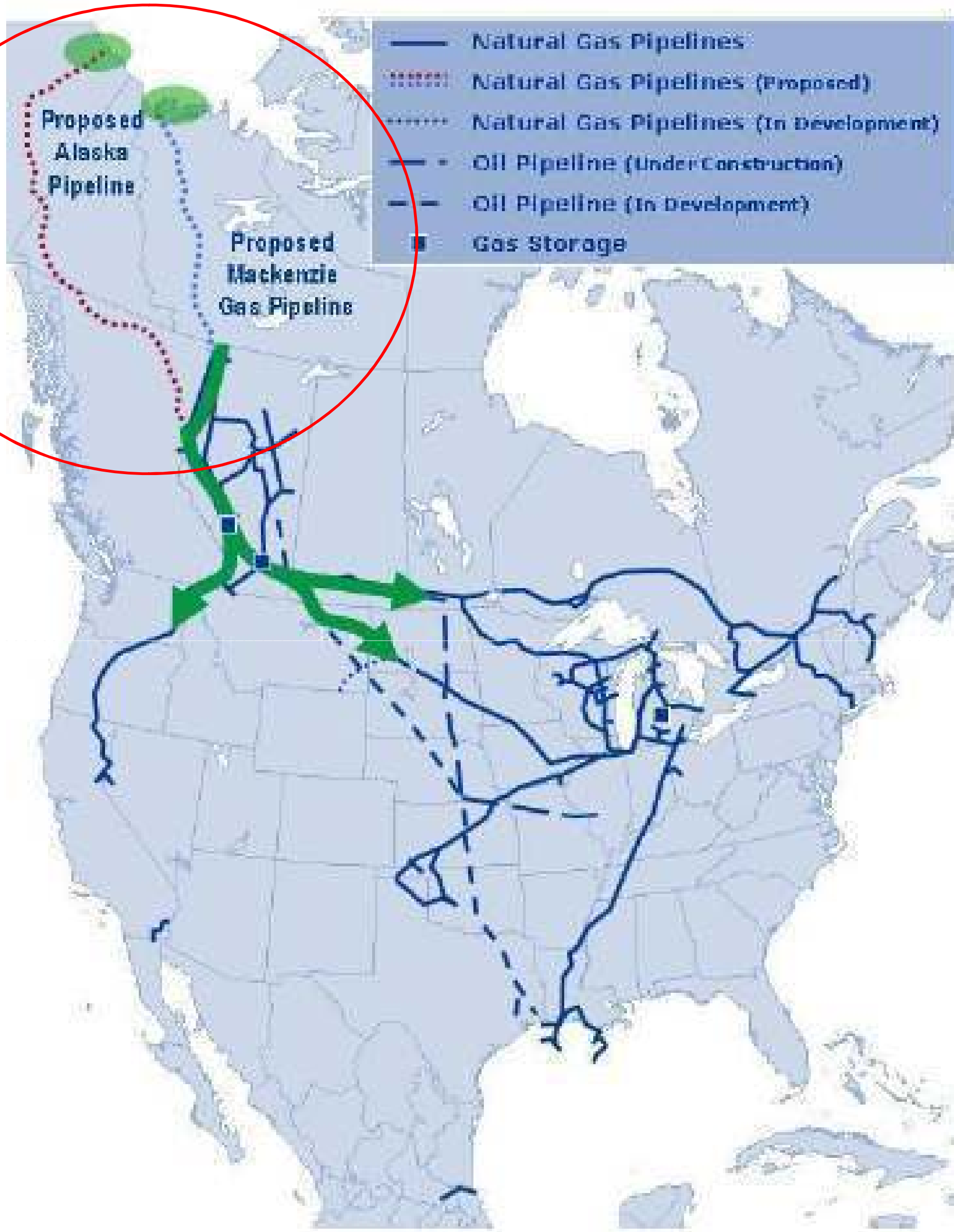
KITIMAT LNG
The 291-mile Pacific Trail Pipeline would connect natural gas from Spectra Energy Transmission's pipeline at Summit Lake, north of Prince George, BC, to the proposed Kitimat LNG export terminal in BC's Bish Cove.

OREGON LNG
117-mile pipeline would connect a terminal in Warrenton, Ore., to the existing NW Natural and Northwest Pipeline systems near Molalla, Ore.

JORDAN COVE
231-mile Pacific Connector Gas Pipeline would extend from the proposed terminal in Coos Bay, Ore., across southwest Oregon to the California border at Malin, Ore., to serve the Pacific Northwest and California markets.

BUT WILL LNG EVER ARRIVE IN THE PACIFIC NORTHWEST?

OREGON ATTORNEY GENERAL PETITIONED FERC, SAYING THAT THE ORDER APPROVING THE JORDAN COVE LNG TERMINAL IS UNLAWFUL BECAUSE OREGON HASN'T SIGNED OFF ON THE PROJECT'S COMPLIANCE WITH WATER QUALITY STANDARDS AND COASTAL ZONE MGMNT PLAN OR PROVEN THERE IS EVEN STILL A NEED FOR THE GAS



Northern Projects: Recent Developments

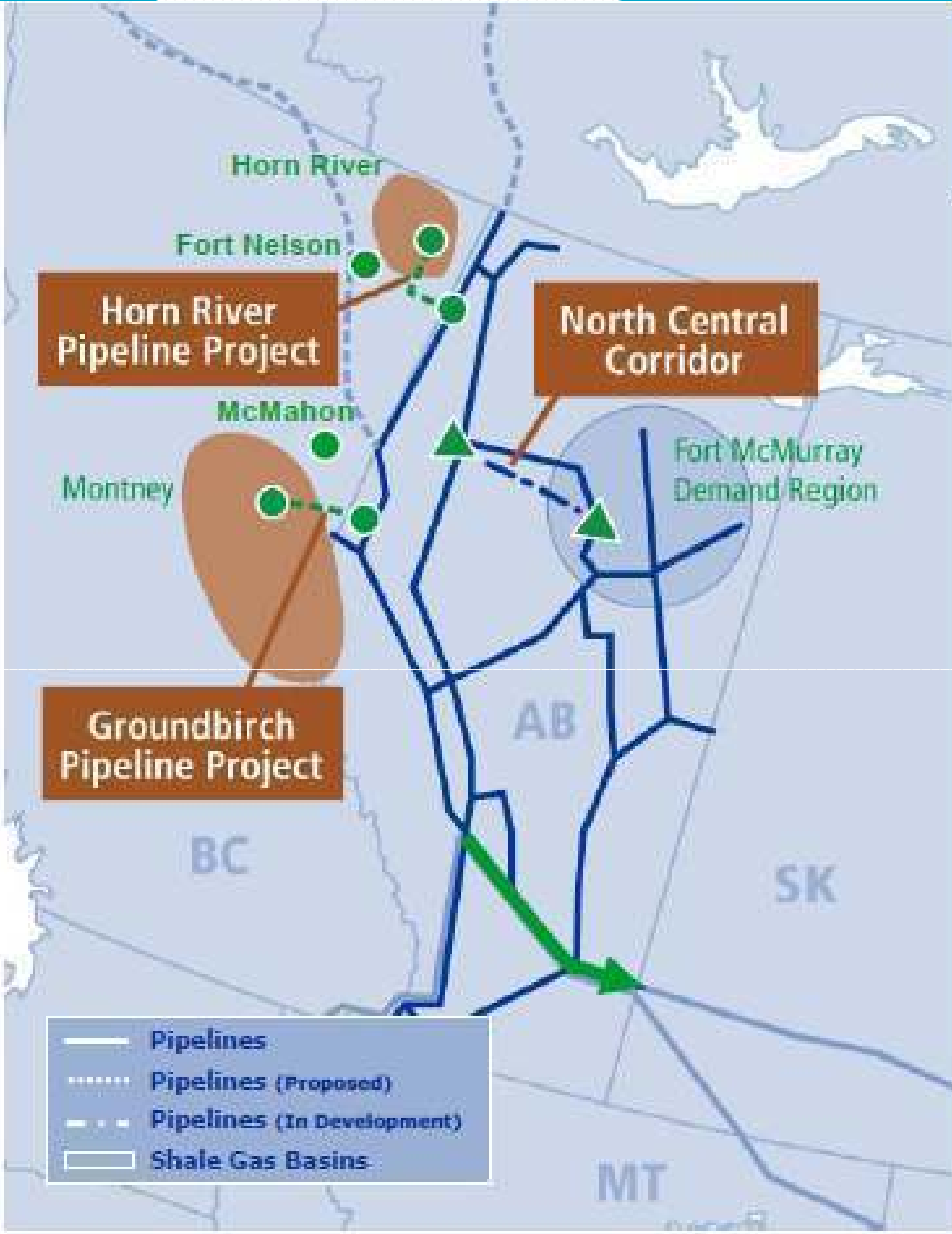
Mackenzie Gas Project

- Joint Review Panel report – Dec 2009
- NEB Reasons for Decision on MGP application – Sept 2010
- Financial restructuring discussions on-going

Alaska Pipeline Project

- AGIA license issued Dec 2008
- June 2009 - TransCanada and ExxonMobil joint venture
- All AGIA commitments remain with TransCanada
- Next step is open season mid-2010

TransCanada



Alberta System Update

North Central Corridor
- 300 km of 42-inch pipe
- 26 MW of compression
- Approximately $925 million
- In-service 2010

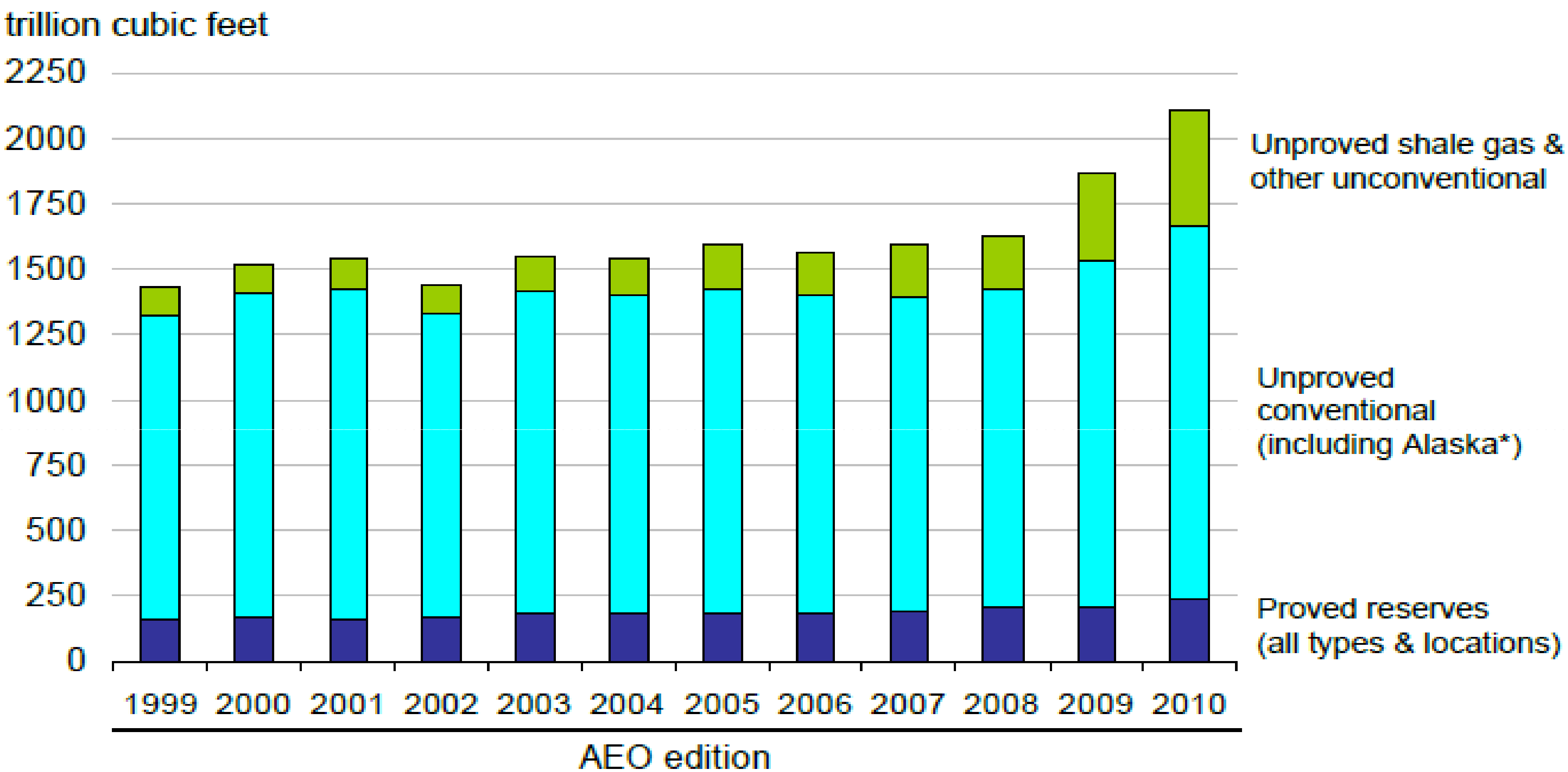
Groundbirch Pipeline Project
- Commitments for 1.1 Bcf/d by 2014
- 77 km, 36-inch pipe
- Approximately $250 million
- Expected in-service Q4 2010

Horn River Pipeline Project
- Commitments for 378 MMcf/d in 2013
- 155 km combination of NPS 30 and existing pipe
- Approximately $340 million
- Expected in-service Q2 2012

AB Jurisdiction Application Approved
- Extend Alberta system across provincial borders
- Integrated service to AB and BC customers, and Northern gas producers

TransCanada

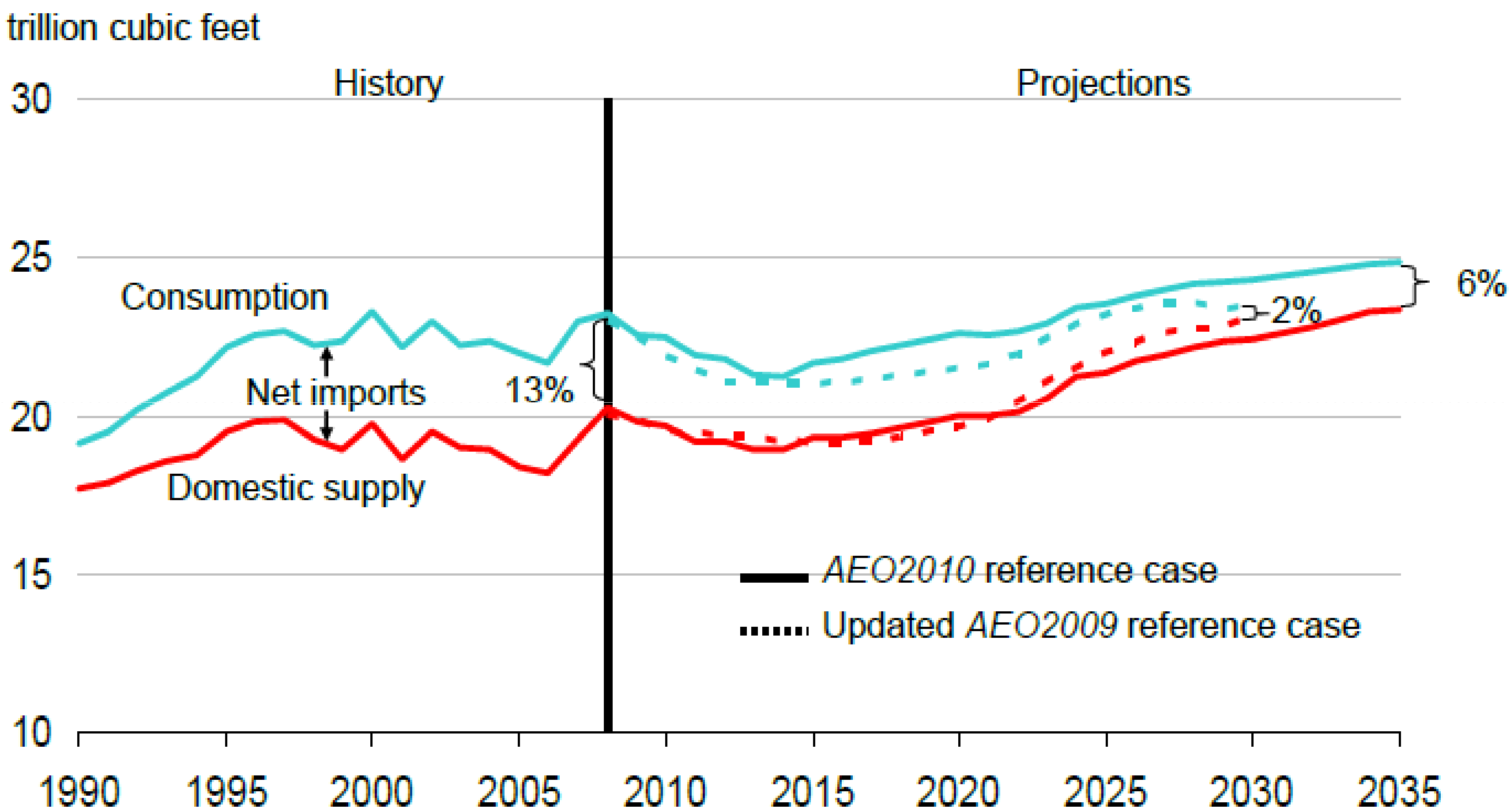
Shale gas has been the primary source of recent growth in U.S. technically recoverable natural gas resources



* Alaska resource estimates prior to *AEO2009* reflect resources from the North Slope that were not included in previously published documentation.

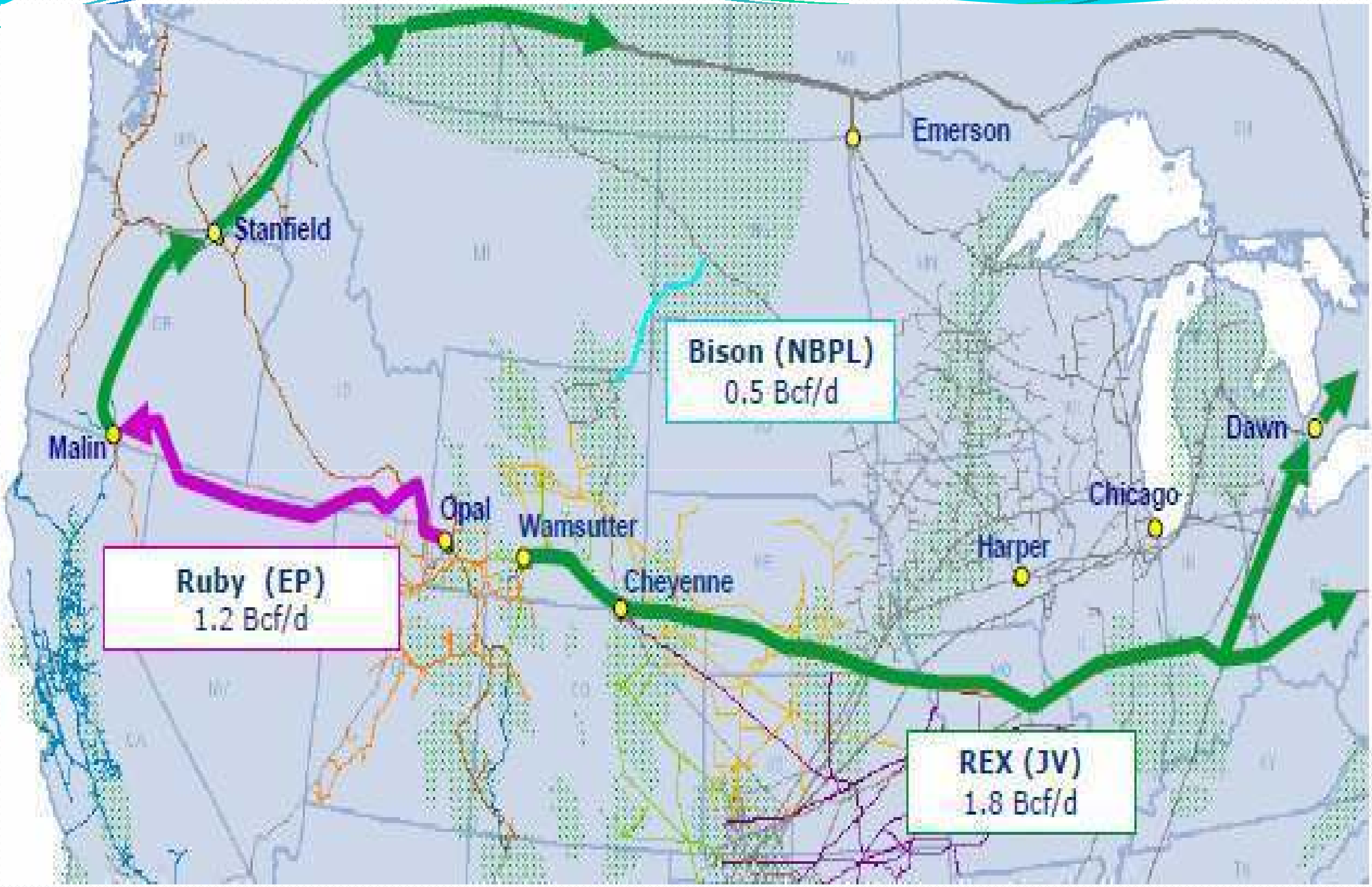
Source: U.S. Geological Service, Mineral Management Service, private data, and EIA.

Import share of natural gas supply declines as domestic supply grows



Richard Newell, SAIS, December 14, 2009

Source: *Annual Energy Outlook 2010*


Emerson
Stanfield
Bison (NBPL)
0.5 Bcf/d
Malin
Dawn
Chicago
Opal
Wamsutter
Harper
Cheyenne
Ruby (EP)
1.2 Bcf/d
REX (JV)
1.8 Bcf/d

CAPACITY OPTIONS

- EXTENSION OF TERM FOR CITYGATE PURCHASES
- CONTINUE TO RECALL X85 CAPACITY, SPECIFICALLY ALONG THE WENATCHEE LATERAL WHICH ENSURES CORE WILL HAVE SUFFICIENT FIRM RIGHTS
  - EVEN AS GROWTH HAS TAPERED OFF THE LATERAL IS CONSTRAINED ON AN OVERALL BASIS, SO WE CONTINUE TO ENGAGE PARTIES
- TCPL-NOVA ADDITIONAL CAPACITY
- NWP RELINQUISHED CAPACITY OR EXPANSION
- PROPOSED PIPELINES

CAPACITY OPTIONS

Long Range Possibilities

- EXPAND CNG SYSTEM TO INTERCONNECT WITH OTHER NEAR-BY PIPELINES
- ACQUIRING CAPACITY ON OTHER ROCKIES PIPELINES (OVERTHRUST, CIG, ETC) TO ACCESS SUPPLIES
- POSSIBLE GTN EXPANSIONS ACROSS WASHINGTON (MOSES LAKE LINE), OREGON, OR BC (TCPL-GTN)
- EXTEND DIRECT CONNECT LINE FROM SPECTRA

Source: NWGA 2010 Gas Outlook Study

SUNSTONE PIPELINE SPECIFICATIONS

- 585-mile, 42-inch diameter pipeline
- Joint venture between TransCanada GTN and Northwest Pipeline
- Up to 1.2 billion cubic feet per day
- In service 2011
- Parallel to NWP between Opal Hub and Stanfield OR
- Connect to TransCanada GTN at Stanfield
- ***Due to current market conditions, Williams and TransCanada discontinued development work in Fall 2009.***

BLUE BRIDGE PIPELINE PROJECT

- Williams/Northwest Pipeline
- Up to 119 miles of looping pipeline and installing additional compression.
- Planned to deliver up to 300 MMcf/d from Plymouth, Wash., to the I-5 Corridor.
- The project would generally follow Northwest Pipeline's existing pipeline corridor for most of its route.
- FERC recently held public meetings on the project.
- Project design continues to evolve

PALOMAR PIPELINE PROJECT

•Joint development between TransCanada and Northwest Natural

•Approximately 217 miles of 36-inch diameter pipe

•GTN Mainline near Madras to Columbia River

•Interconnect with proposed Bradwood Landing LNG facility

•Pipeline planned irrespective of LNG facility online

•Bi-directional capacity of up to 1 Bcf/day

•Federal approval to build is expected in late 2010

•Connects to Mist underground storage

RUBY PIPELINE PROJECT

- Development by El Paso Natural Gas
- Approximately 675 miles of 42-inch diameter pipe
- From Opal Hub to Malin OR
- Initially 1.5 Bcf/day
- May have possible backhaul into GTN
- Construction is expected pending financial and final regulatory and environmental approval

SOUTHERN CROSSING PIPELINE EXTENSION

•Terasen Gas is developing

•Extend Southern Crossing from Oliver to Kingsvale BC

•200 MMcf/d, possible expansion to 400 MMcf/d

•Bi-directional; new production from northern BC could flow to east via GTN or move AB gas into I-5 via Westcoast Spectra

CAPACITY ISSUES

POTENTIAL RATES AND PRICING IMPACTS

- NWP
  - Must file a rate filing no later than July 1, 2012
- SPECTRA PIPELINE
  - Interested parties will be in settlement negotiations for 2010 Tolls soon
  - A multi-year deal is likely
  - De-contracting continues to be an on-going issue
- TCPL-FOOTHILLS
  - In October 2009, the NEB decided to end the 15 year-old return on equity formula to determine cost of capital
  - Cost of capital will now be negotiated between Foothills and shippers
  - Settlement negotiations begin in February 2010

CAPACITY ISSUES

- **TCPL-GTN**
  - **–Cannot file another rate filing before June 30, 2011 for a January 1, 2012 effective date**
  - **–De-contracting continues to be an on-going concern, particularly if Ruby Pipeline happens or there is no firm backhaul capability**
- **TCPL-NOVA**
  - **–Settlement discussions on revenue requirements on-going**
  - **–Concerns regarding extraction rights**
  - **–Significant issues Ft Nelson and McMahon expansions may impact rates and liquidity**

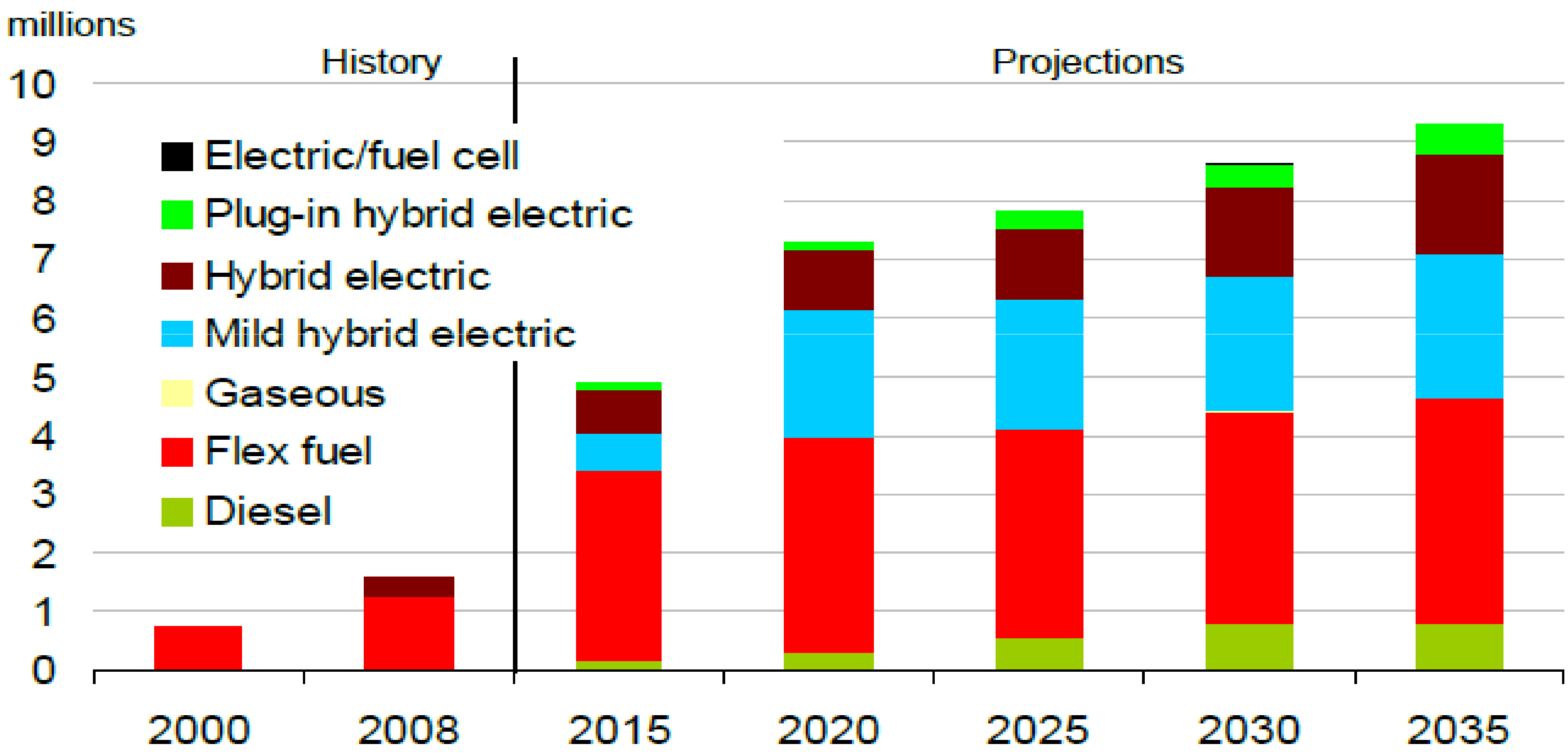
OTHER SUPPLY SIDE RESOURCE OPTIONS

- NEGOTIATE ALTERNATE FUEL CONTRACTS WITH NON-CORE CUSTOMERS
- PROPANE AIR PLANTS
- ALASKAN GAS VIA SPECTRA AND/OR TCPL
- BIO-FUELS

Bio-fuels

- **Biofuels meet most of the growth in liquid fuels supply**
- **Biofuels grow, but fall short of the 36 billion gallon renewable fuels standards target in 2022, exceed it in 2035**
- **New light duty vehicle efficiency reaches 40 mpg by 2035**
- **We continue to believe that viable quantities of targeted biomass will be available along in Zones 10 and 11 in the next few years**

Mild and full hybrid systems dominate new light-duty vehicle sales by 2035



Richard Newell, SAIS, December 14, 2009

Source: *Annual Energy Outlook 2010*

CARBON AND ENERGY POLICES

Policy makers continue to address climate change

Designed to change how we produce and use energy

Reduction greenhouse gas emissions, via technology, consumer grants, tax credits

Natural gas, as cleanest fossil fuel will be critical

CARBON AND ENERGY POLICES

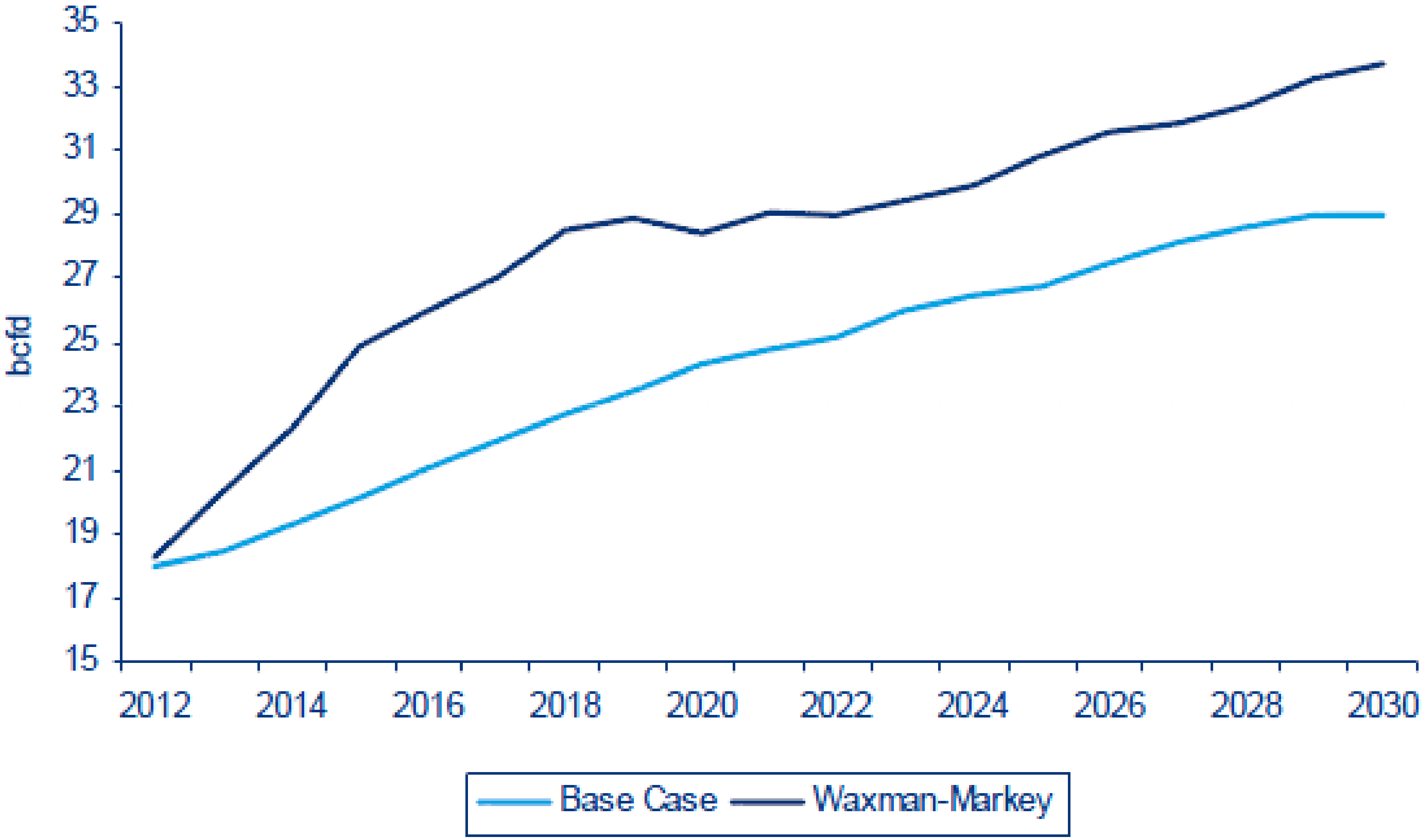
Waxman-Markey Bill (American Clean Energy and Security Act)

Passed US House or Representatives June 2009

83% reduction of carbon emissions from 2005 levels by 2050
US Senate working on a 30% tax credit to convert home heating systems

Canadian House of Commons considering bill which calls for GHG emissions of 80% below 1990 levels by 2050

Gas Demand for Power Under Base Case and Waxman-Markey



Source: Wood Mackenzie

CARBON AND ENERGY POLICES

Non-fossil energy use grows rapidly, but fossil fuels still provide the vast majority of total energy use in 2035

Demand increase

Pressure on supplies

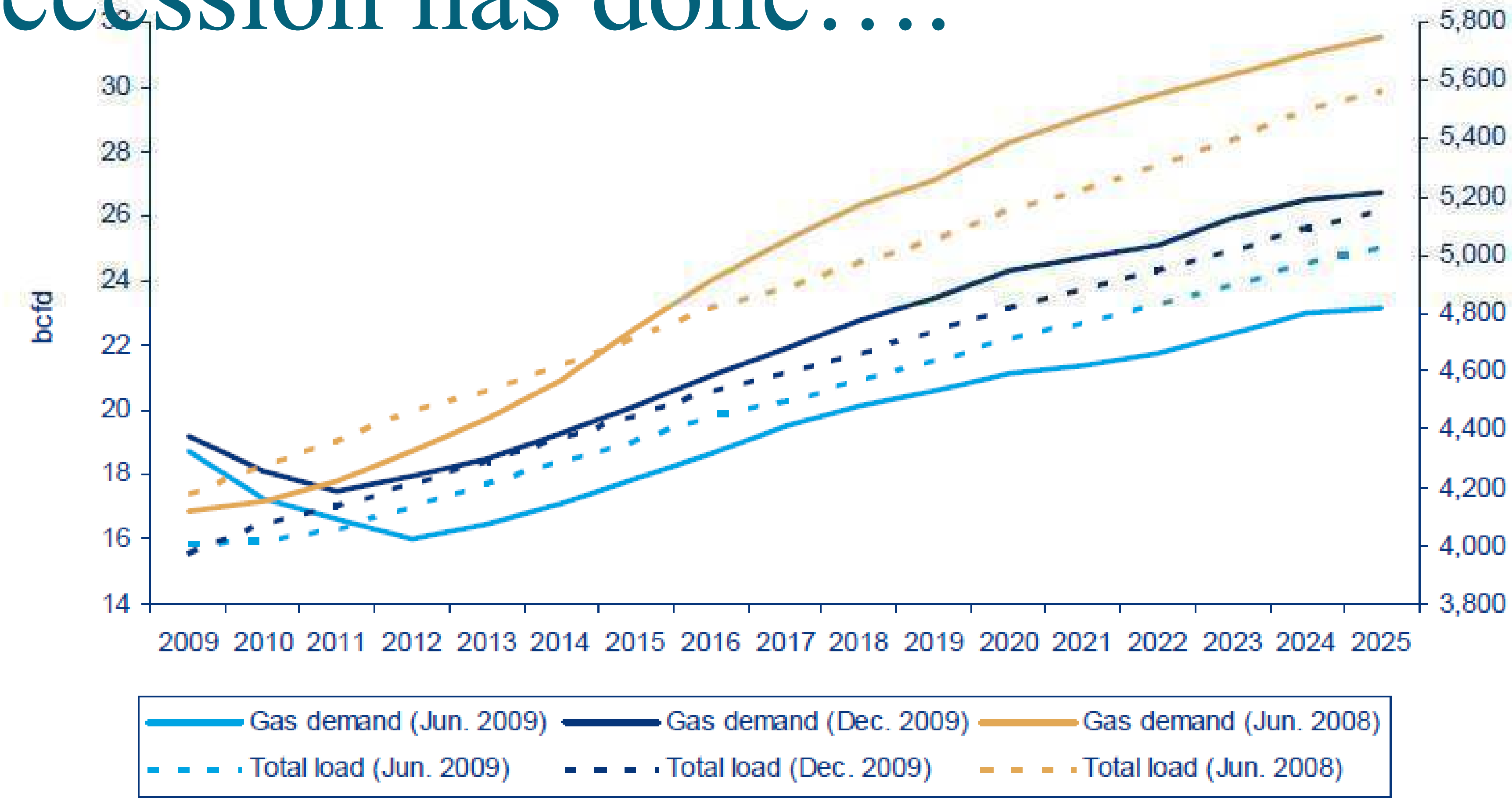
To achieve emission goals there is the potential for increased prices via fees and taxes, or as a result of increased gas demand and competition for the resource

Natural gas and renewables account for the majority of power capacity additions from 2008 to 2035

Renewables gain electricity market share; coal share declines; nuclear and wind use increase

Coal retirements could add as much as 5 bcf/d of gas demand over the next decade (Wells Fargo, 1/13/2010)

US Gas Demand for Power Generation….look what the recession has done….

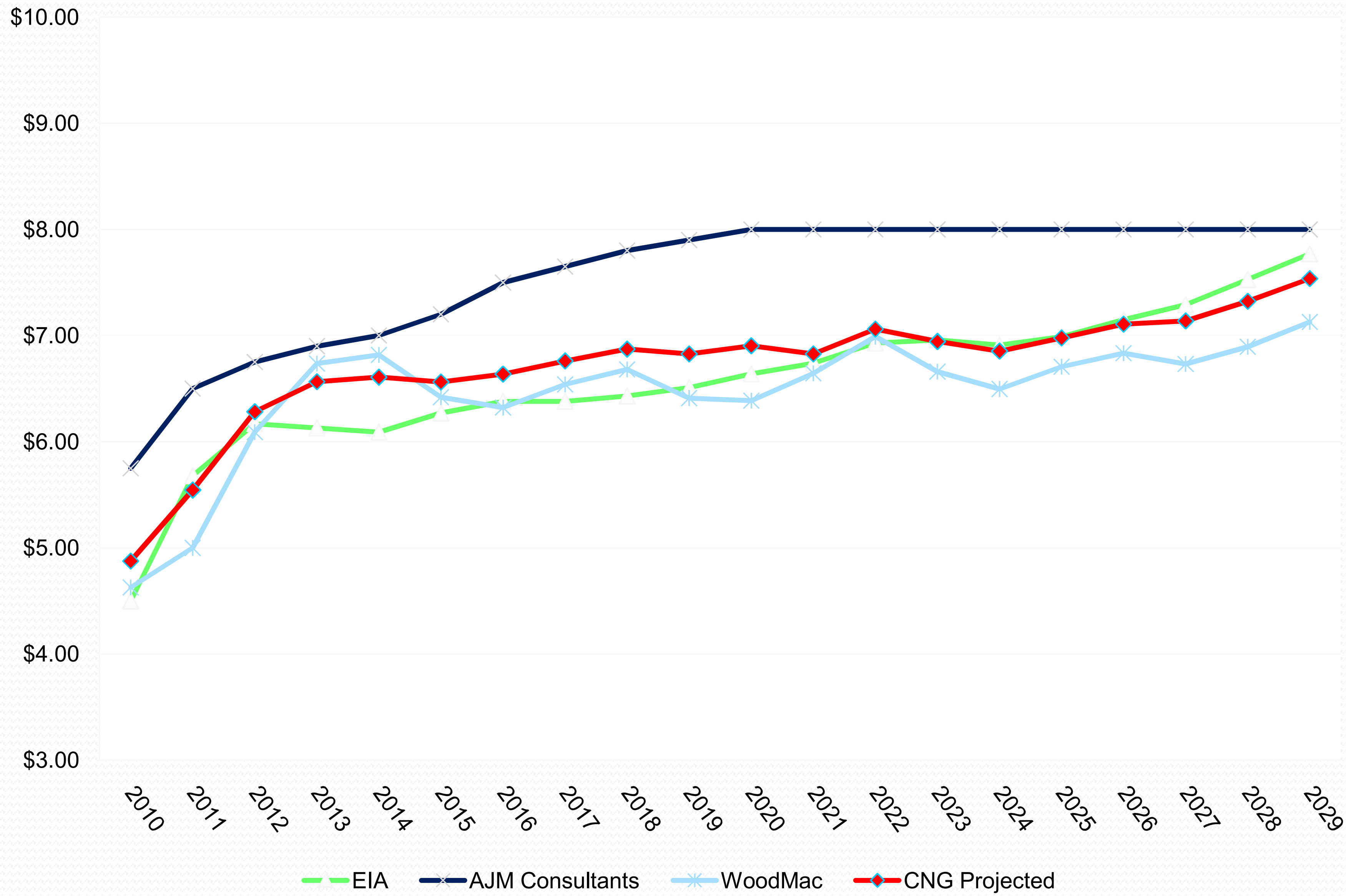


Source: Wood Mackenzie (NAGS, NAPS)

Natural Gas Price Drivers

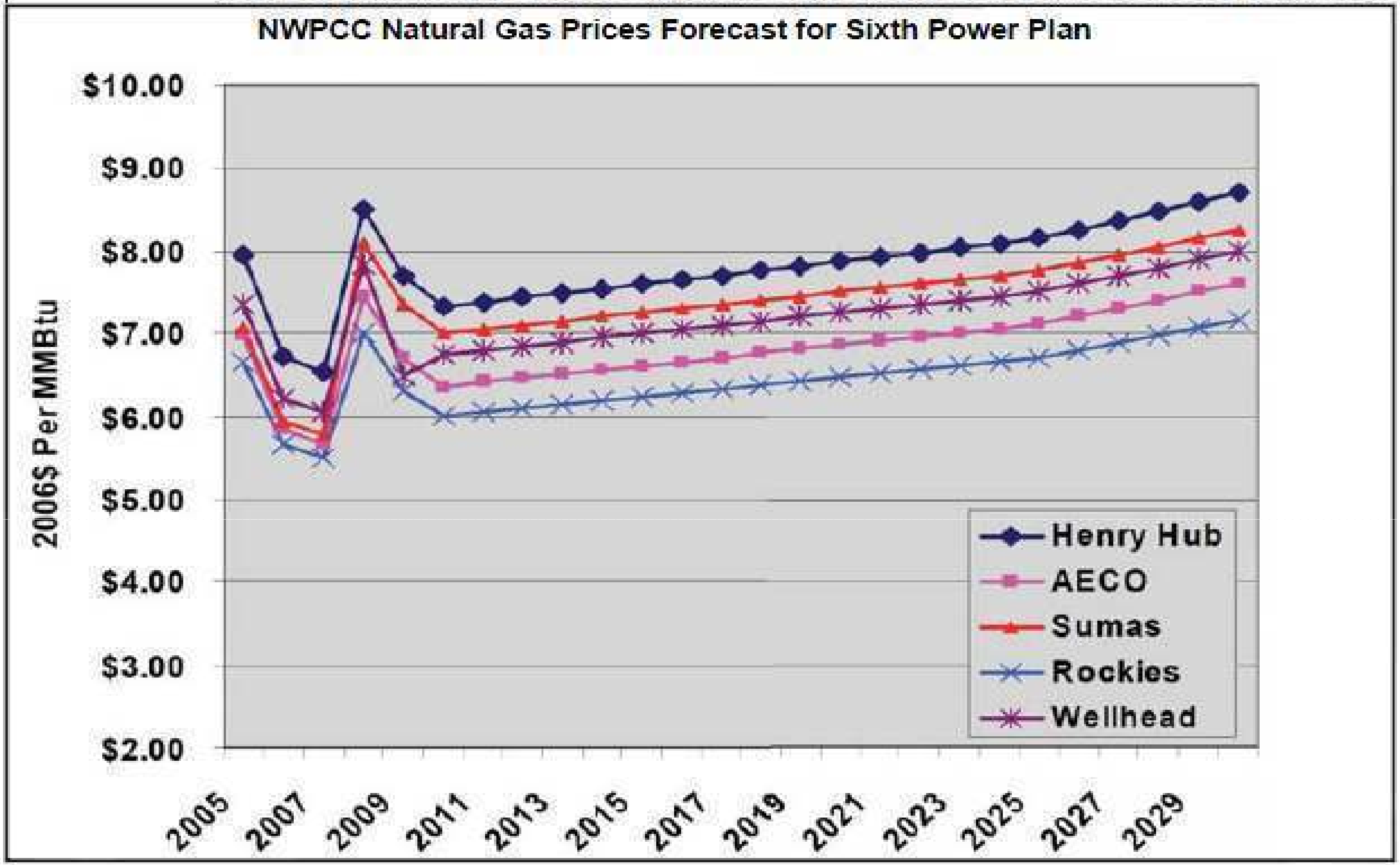
Natural gas wellhead price are projected to rise from low levels experienced during 2008-2009 recession

Long-Range NYMEX HH Price Forecast

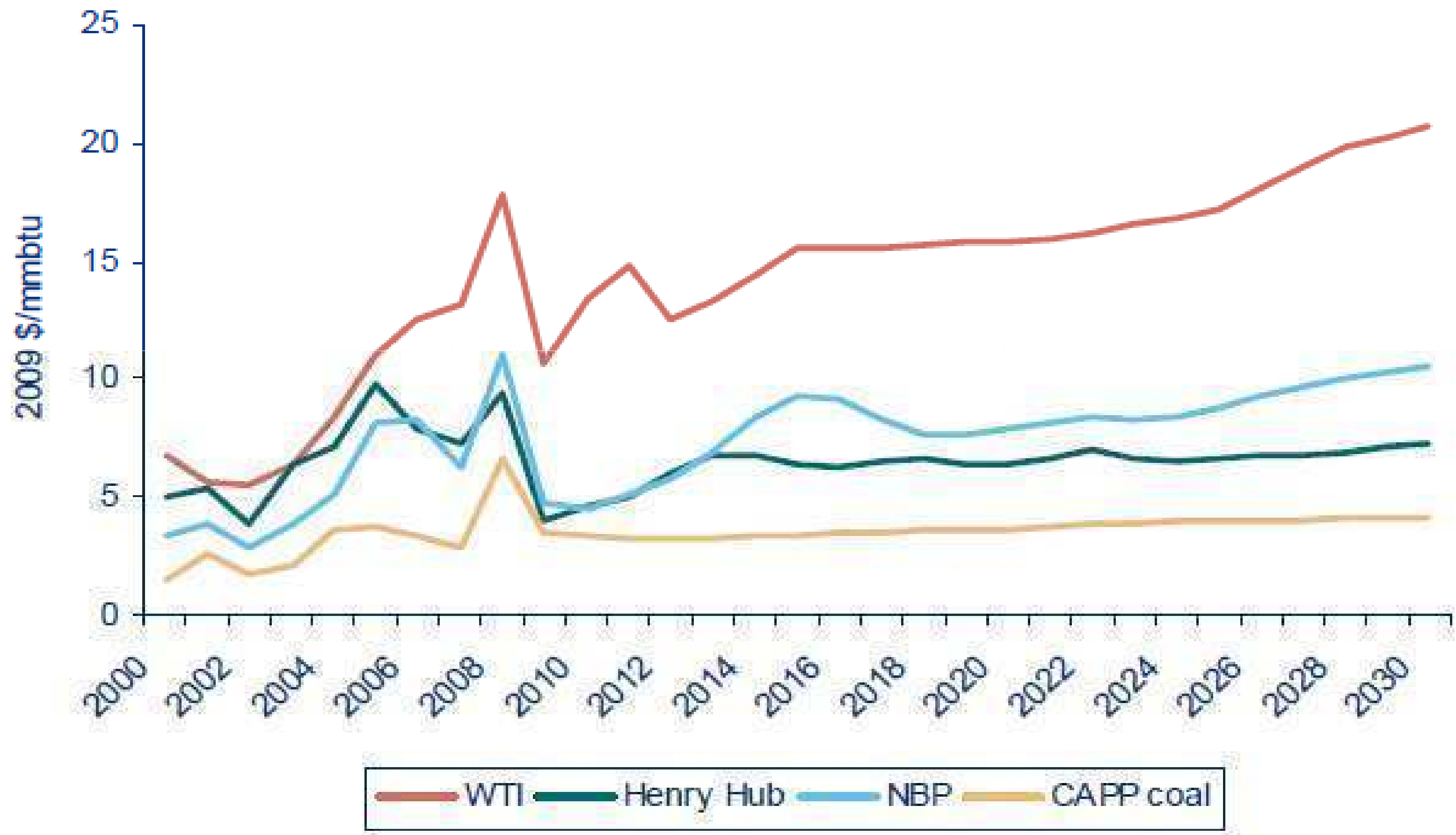


Page 169

NWPCC NATURAL GAS PRICE FORECAST FOR SIXTH POWER PLAN

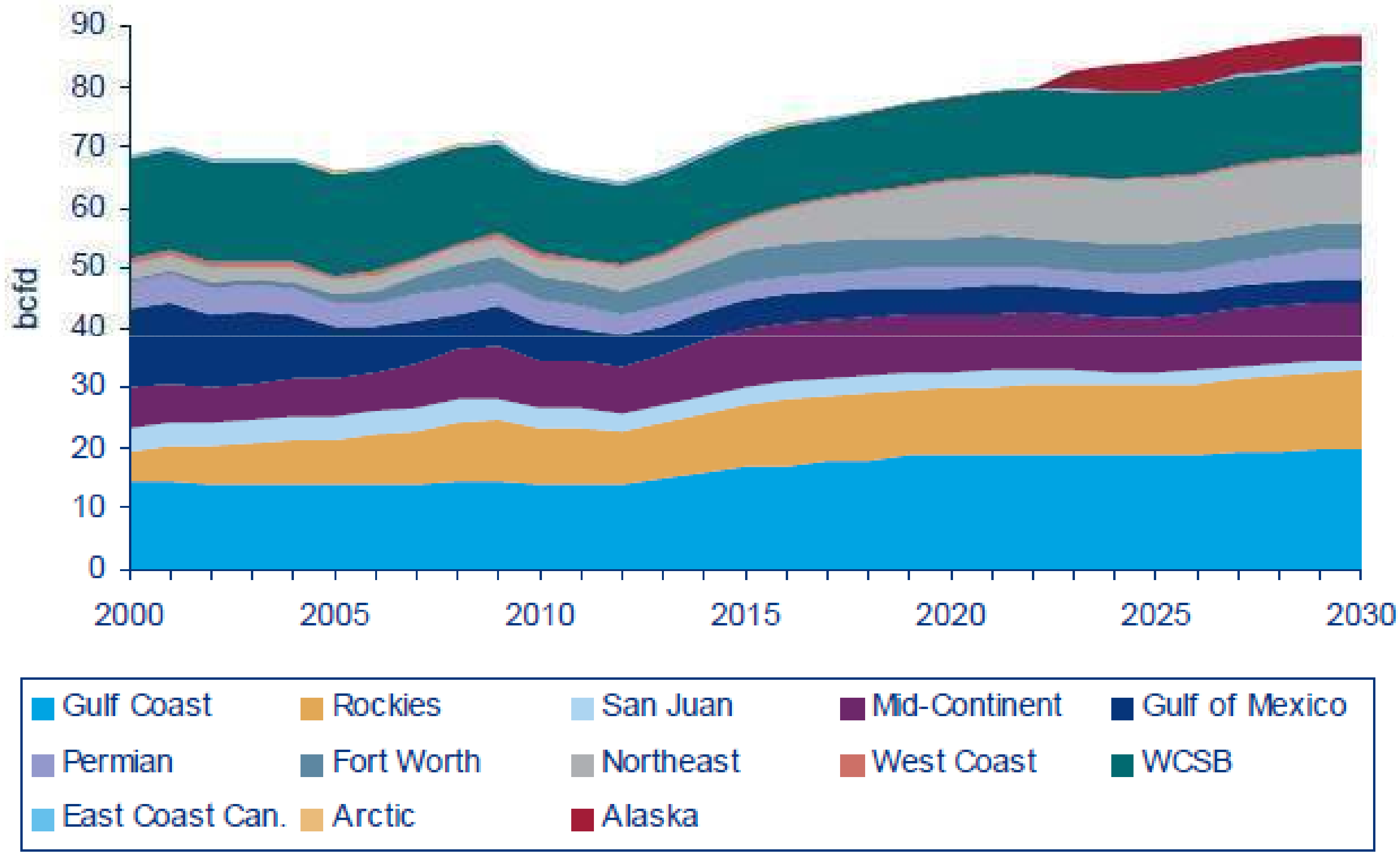


FUEL PRICE OUTLOOK

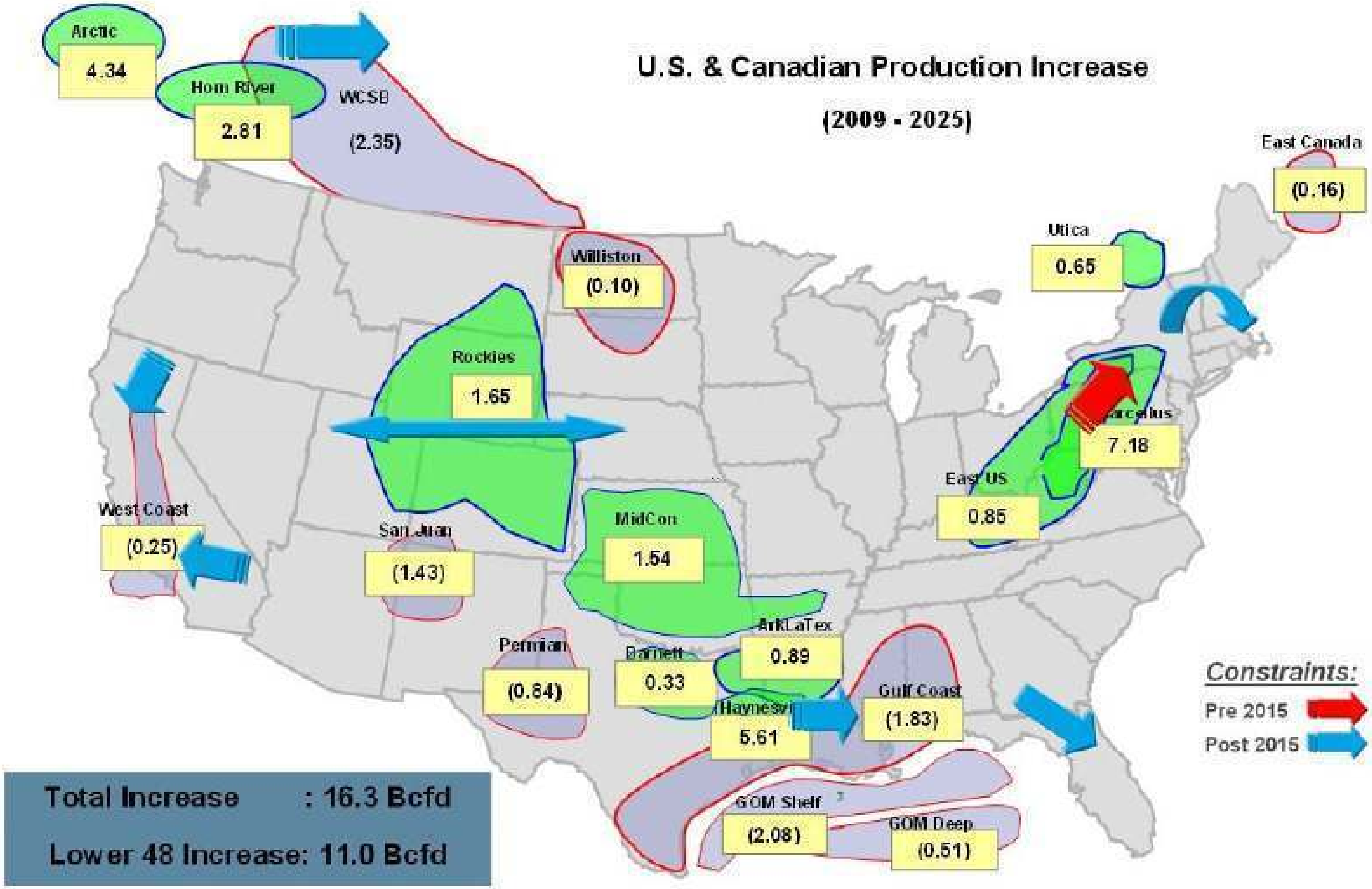


Source: Wood Mackenzie (NAGS, Global Gas Service, Macro Oils, Coal Market Service North America)

North American Supply Forecast by Region



Source: Wood Mackenzie



Source: Wood Mackenzie

LONG-TERM FORECAST

	2009	2010	2011	2012	2013	2014	2015	2020	2025	2030
US power sector gas demand (bcfd)	19.2	18.7	18.4	18.0	18.5	19.2	20.1	24.3	26.7	29.0
US gas demand (bcfd)	62.9	62.8	62.6	61.7	62.5	63.6	65.1	70.7	75.4	79.5
US gas supply (bcfd)	57.6	54.1	52.9	51.7	53.6	56.8	59.6	66.1	71.7	76.3
US shale gas supply (bcfd)	7.9	8.8	9.7	10.7	12.1	13.4	14.7	20.8	23.7	30.3
Canadian exports to the US (bcfd)	6.9	6.3	5.6	5.1	4.9	4.7	4.1	4.0	4.1	4.7
LNG imports (bcfd)	1.3	3.5	4.5	4.5	3.9	2.5	2.4	1.5	1.1	0.9
Henry Hub prices (2009 $/mmbtu)	$4.00	$4.63	$5.00	$6.09	$6.74	$6.82	$6.42	$6.39	$6.71	$7.28
AECO prices (2009 $/mmbtu)	$3.55	$4.24	$4.65	$5.73	$6.38	$6.46	$6.12	$6.10	$5.77	$6.16

Source: Wood Mackenzie

PRODUCTION

- With the economics in the emerging shales improving, operators aggressively developing these plays.
- Shale gas production, which accounts for about 14% of the US production this year, some sources believe shale is set to comprise more than a third of US production by the mid 2020’s.
- Well performance in the Horn River play has improved, although players must overcome a multitude of challenges, including a remote operating environment, water availability and disposal issues, infrastructure constraints, and high upfront capital costs Canadian production and exports anticipated to decline

PRODUCTION

- The Alaska pipeline project, designed to deliver 4.5 bcfd from Alaska's North Slope into Alberta and/or the US Lower-48, is still not dead, with two competing projects still officially in the works. Both the BP-ConocoPhillips Denali Pipeline and the TransCanada-ExxonMobil Alaska Pipeline Project plan open seasons during 2010

- Lower-48 shale development has called into question the ultimate need for this project but indicators are that eventually it will get done around 2023

PORTFOLIO PURCHASING STRATEGY

- **Ensure All Core Customers' Natural Gas Needs are Met -**
  - **Through Disciplined Market Analysis and Supply Contracting**
- **Effectively Manage Wholesale and Retail Gas Prices –**
  - **Through Cost-Effective Spot Purchases When Available**
  - **Participating in pipeline regulatory proceedings to Ensure Lowest Pipeline Rates**
- **Mitigate Price Volatility for Customers -**
  - **Through Multi-Year Hedging and a Diversified Portfolio, including both index and fixed price physical products**
- **Minimize Corporate Risk -**
  - **Through the Use of Financial Derivatives**
- **Optimize Pipeline Capacity, Storage, and Other Core Resources -**
  - **Through Available Release Mechanisms**

PROBABLE SCENARIOS

Reference case	Existing supply contracts, incremental supplies (peaking, annual, seasonal and citygate) from various receipt points (AECO, Rockies, Sumas, Station 2, as well as behind the citygate. Incremental supplies also include Biomass, satellite LNG (behind citygate), imported LNG, current upstream pipeline transport capacity, as well as proposed pipelines and extensions (Blue Bridge, Ruby, Palomar, Southern Crossing, etc.). We also include Cascade's current Jackson Prairie storage accounts and our Plymouth LNG account.
All Resources	Existing supply contracts, incremental supplies (peaking, annual, seasonal and citygate) from various receipt points (AECO, Rockies, Sumas, Station 2, as well as behind the citygate (satellite LNG). Incremental supplies also include Biomass, satellite LNG (behind citygate), imported LNG (Kitimat, Jordan Cove, Bradwood Landing), current upstream pipeline transport capacity, as well as proposed pipelines and extensions (Blue Bridge, Ruby, Pacific Connector, Palomar, etc). We also include Cascade's current Jackson Prairie storage accounts, our Plymouth LNG account, as well as the potential to obtain AECO and Mist storage.
Basecase Limited Canadian Imports	Model contains all the elements of the Basecase, but incremental Annual AECO and seasonal Sumas resources are unavailable to the model. Additionally, annual Sumas max is lowered from 100,000 to 50,000 dths. The intent to is to restrict the amount of Canadian imports by at least 20%

PROBABLE SCENARIOS

Basecase No Rockies price advantage	Model contains all the elements of the Basecase; however, all potential incremental resources were priced at NYMEX with no basis adder. In other words, incremental AECO, Sumas and Rockies all have the same price. Incremental resources at Station 2 were not available to the model. Transportation rates were not modified from their basecase levels.
Basecase AECO Storage	Model contains all the elements of the Basecase; however, AECO storage is added as a resource. The inventory is set at 300,000 dths, with daily withdrawal rights of 10,000 dths a day. This storage was setup like the existing Jackson Prairie to be 100% full at the start of each heating season. The model is set up so that Canadian withdrawals can use incremental GTN capacity.

IN ADDITION, WE WILL CREATE OTHER SCENARIOS

- The proposed pipelines at various discount pricing
- MIST storage
- Run each proposed pipeline separately
- Run various backhaul scenario
- Run pipeline stacking
- Give a price advantage to Sumas

SUPPLY

Rolling Five-Year Physical Supply Portfolio

- –A more seasonal approach vs annual approach
- –Based on current market conditions, we are locking in new very few long term supplies during the summer months, allowing us to take better advantage of pricing opportunities regardless of basin
- –We use a RFP process to solicit bids, sending to parties who have met our contract and credit standards
- –We run the bids through our modeling software
- –We also consider operational flexibility, past performance and percentage of overall portfolio when selecting supplier

–Also, looking for attractively priced longer term supplies (e.g. 10 years), primarily with producers

SUPPLY

Spot Market (just-in-time)

Poll several suppliers

Utilize ICE to monitor pricing

Aware of operational considerations

COMET

Market Area Storage: Jackson Prairie and Plymouth

Pricing is typically Index based, although we have fixed price and structured products in the mix

Puts, Calls and other options are also included in the portfolio

Prices are hedged with Multi-Year Financial Swaps for up to 3 years or fixed price physical supplies

FINANCIAL CONSIDERATIONS

- Rolling five-year physical supply portfolio
- Physical supplies based on a warmer-than-normal weather pattern
- Hedged volumes are based on warmer-than-normal core demand
- Disciplined hedge periods over the Spring, Summer, and Fall
- Financial swaps cover one to three years
- Financial pricing indications compared among at least three approved banks
- Pricing indications are also compared with physical suppliers

SUPPLIERS

- Wide range of gas suppliers for both short and long term purchases
- We currently have over two dozen parties in our pool of suppliers
- All suppliers must pass Cascade credit standards
- All suppliers must execute a base NAESB contract
- All suppliers subject to credit review throughout the year
- ***All long term physical supply, financial derivatives, and pipeline capacity transactions must be approved by the Gas Supply Oversight Committee (GSOC)***

Other thoughts, questions, concerns…

- **Are there other ideas or concerns that you feel need to be addressed?**
- **Are there other alternatives we should consider?**

2010 Integrated Resource Plan

Next Technical Advisory Group meeting will held at Cascade's Seattle HQ on March 18, 2010

CASCADE NATURAL GAS CORPORATION®

2010 Integrated Resource Plan

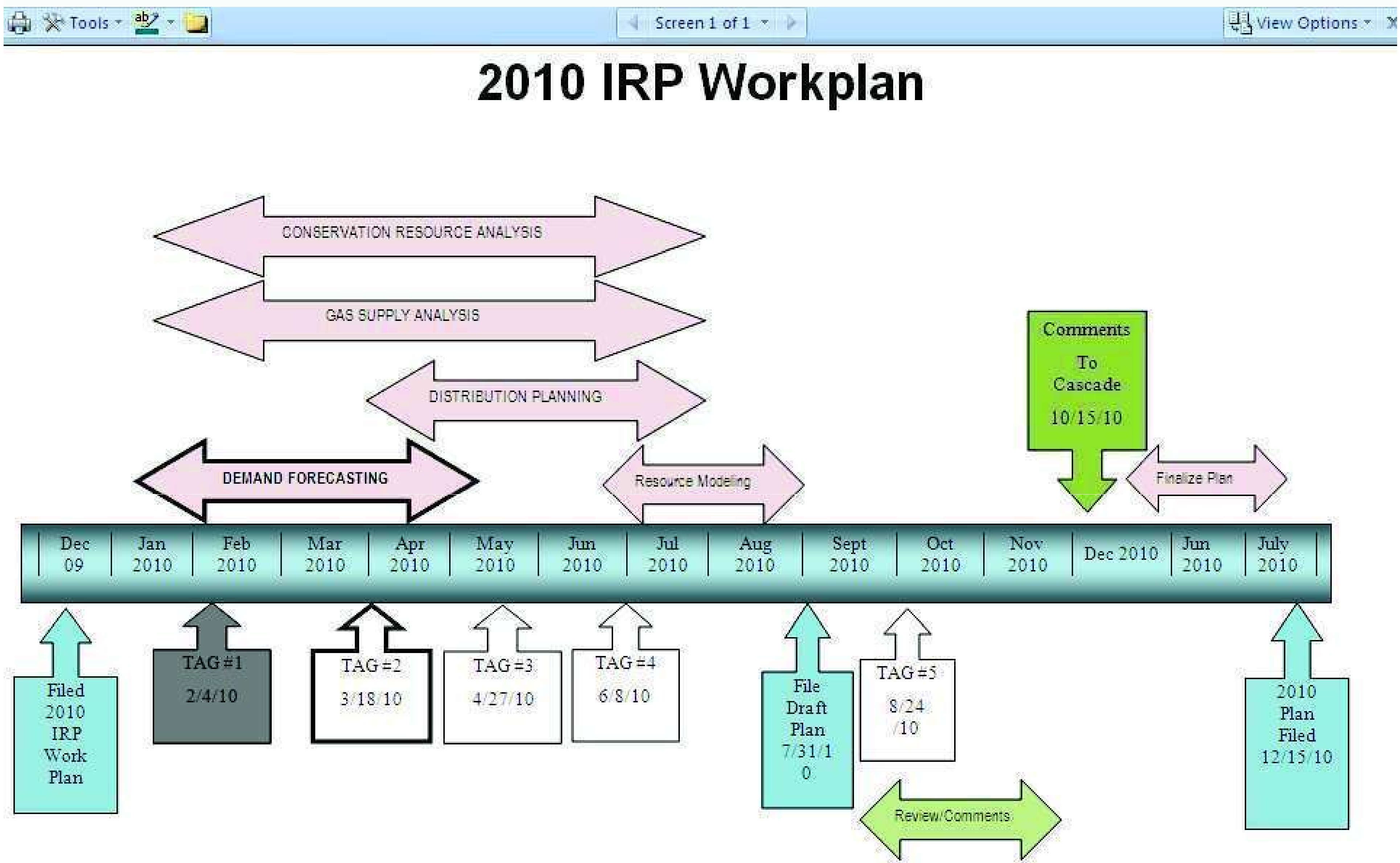
Technical Advisory Group Meeting

March 18, 2010

Agenda

- Introductions
- 2010 IRP Workplan Overview
- Key Assumptions & Demand Forecast
- IRP Next Steps
- Closing Discussion

CASCADE NATURAL GAS CORPORATION ®


Tools
Screen 1 of 1
View Options
2010 IRP Workplan
CONSERVATION RESOURCE ANALYSIS
GAS SUPPLY ANALYSIS
DISTRIBUTION PLANNING
DEMAND FORECASTING
Resource Modeling
Comments To Cascade 10/15/10
Finalize Plan
Dec 09
Jan 2010
Feb 2010
Mar 2010
Apr 2010
May 2010
Jun 2010
Jul 2010
Aug 2010
Sept 2010
Oct 2010
Nov 2010
Dec 2010
Jun 2010
July 2010
Filed 2010 IRP Work Plan
TAG #1 2/4/10
TAG #2 3/18/10
TAG #3 4/27/10
TAG #4 6/8/10
File Draft Plan 7/31/1 0
TAG #5 8/24 /10
Review/Comments
2010 Plan Filed 12/15/10

CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

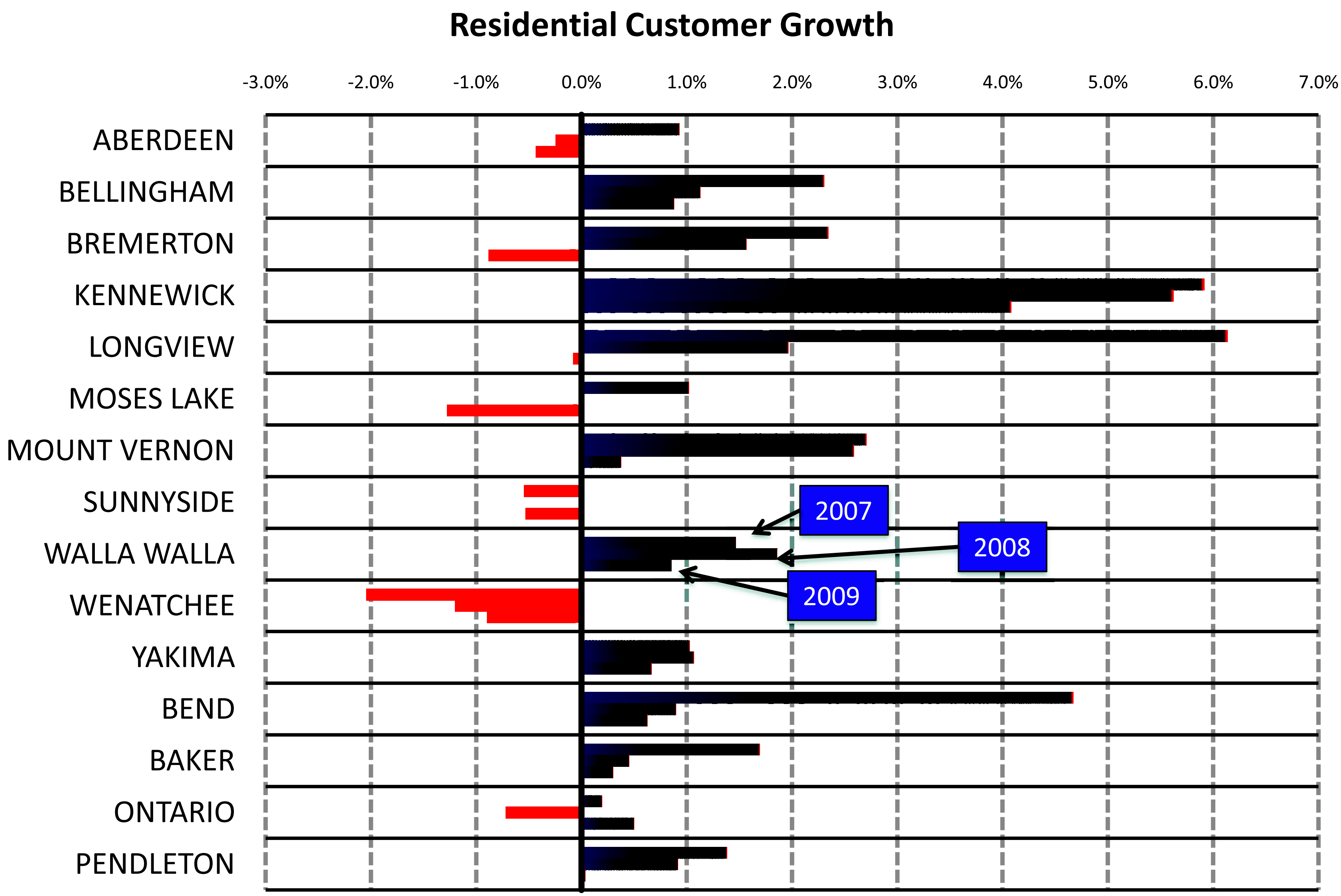
In the Community to Serve®

2010 IRP Demand Forecast Presentation

March 18, 2009

Vas Duggirala
Regulatory Analyst
Cascade Natural Gas
srinivas.duggirala@cngc.com

Current Events



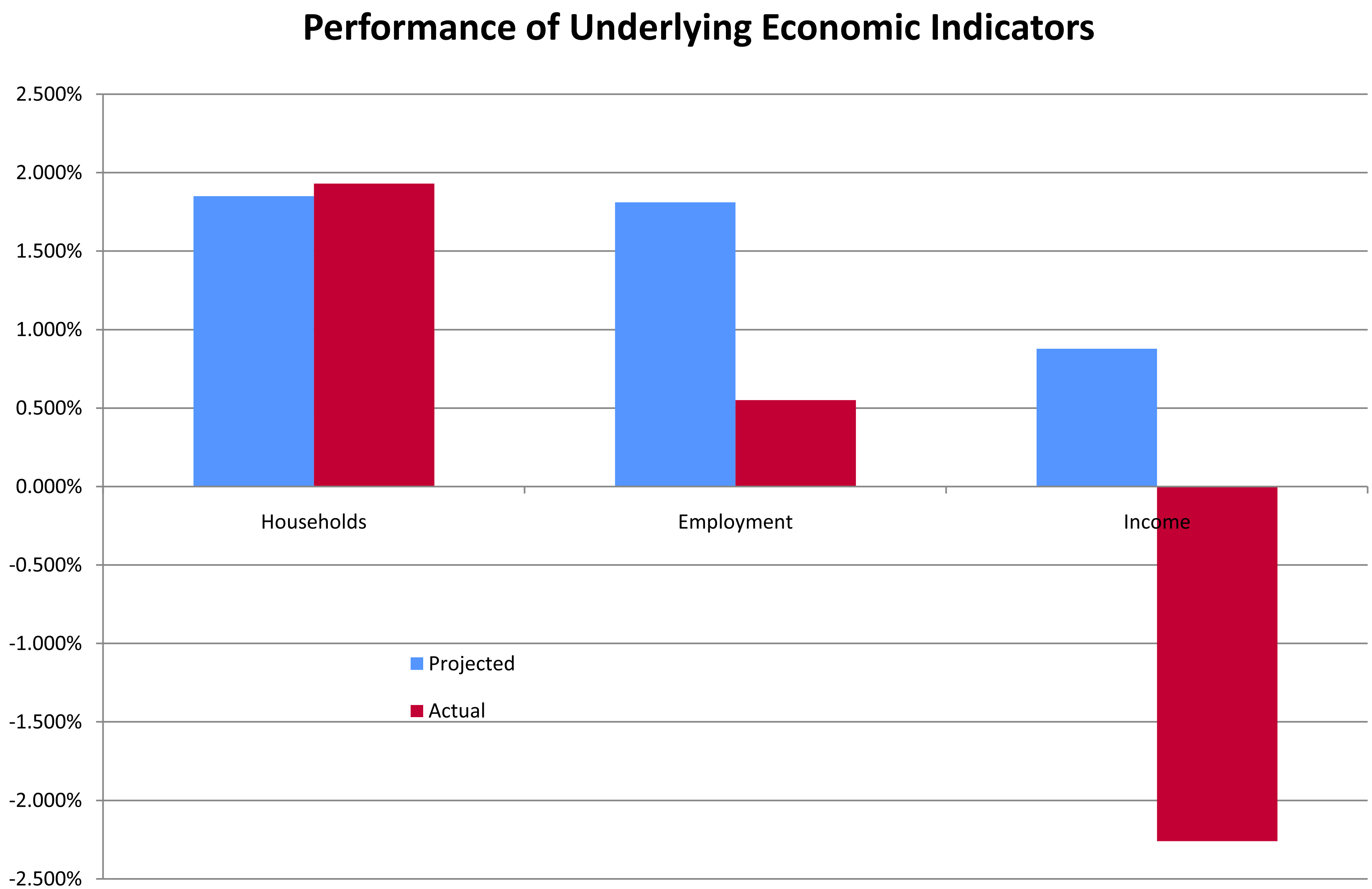
2008 IRP Revisited

Growth has been far lower than expectations:

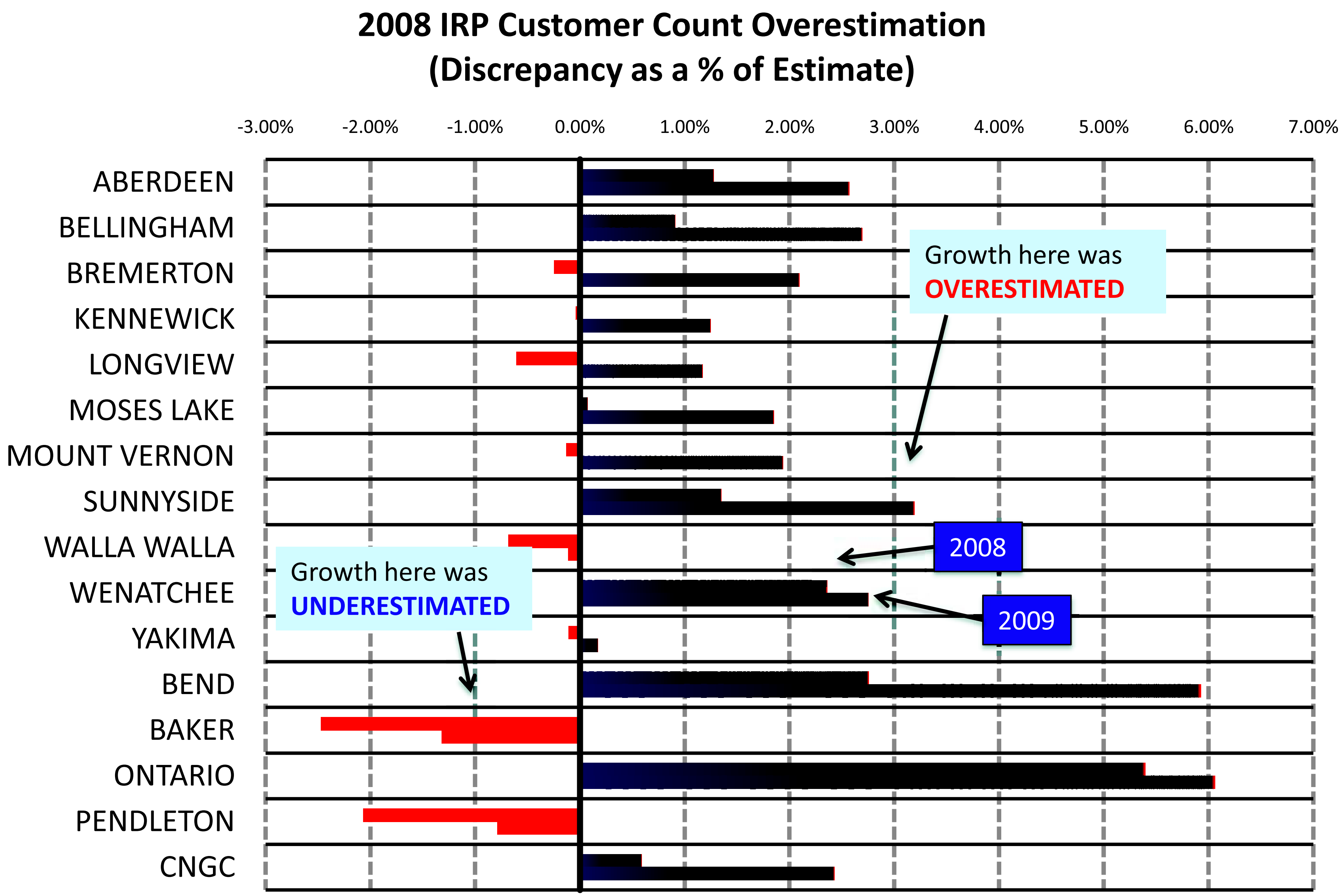
	Forecasted	Actual
2008	2.68%	1.75%
2009	2.35%	0.61%

2008 IRP Revisited

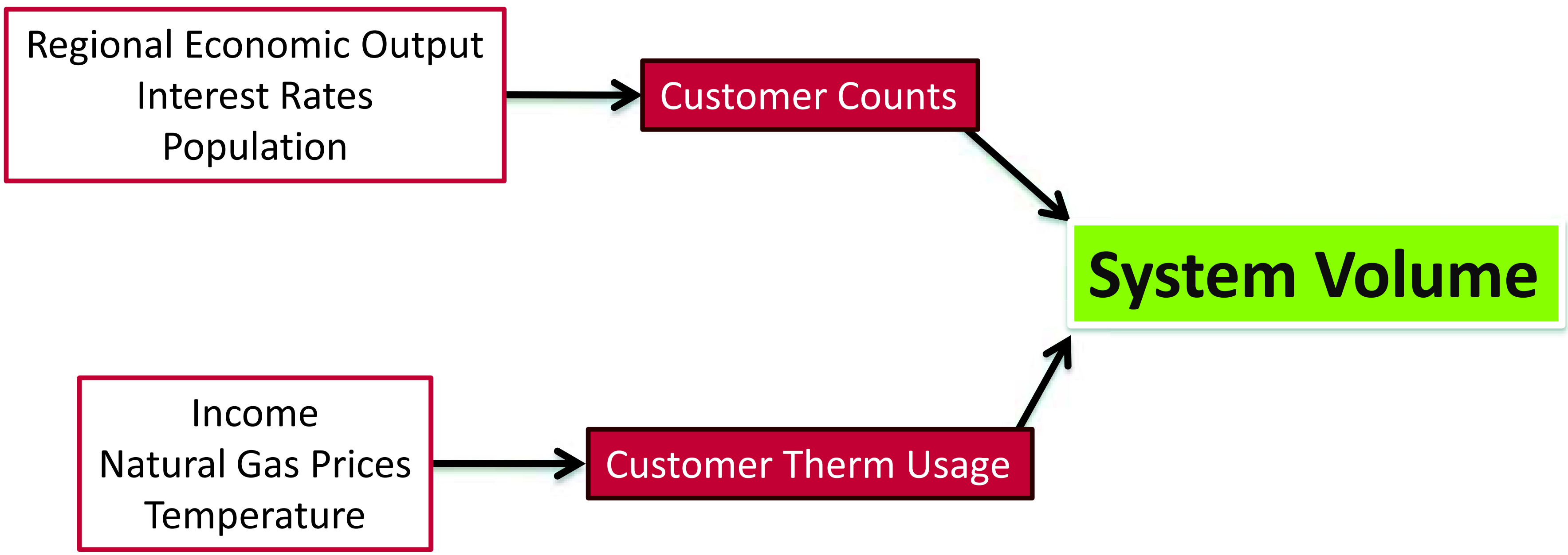
Customer counts have been low, partially due to the economy:



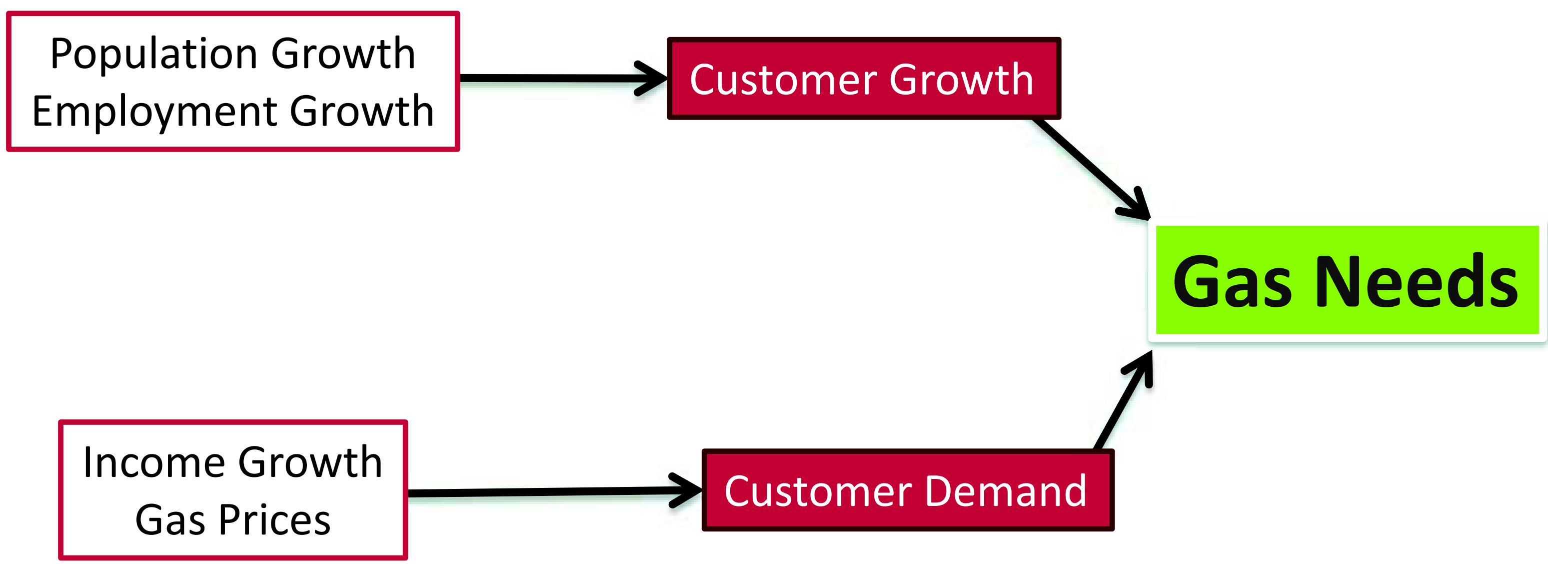
2008 IRP Revisited



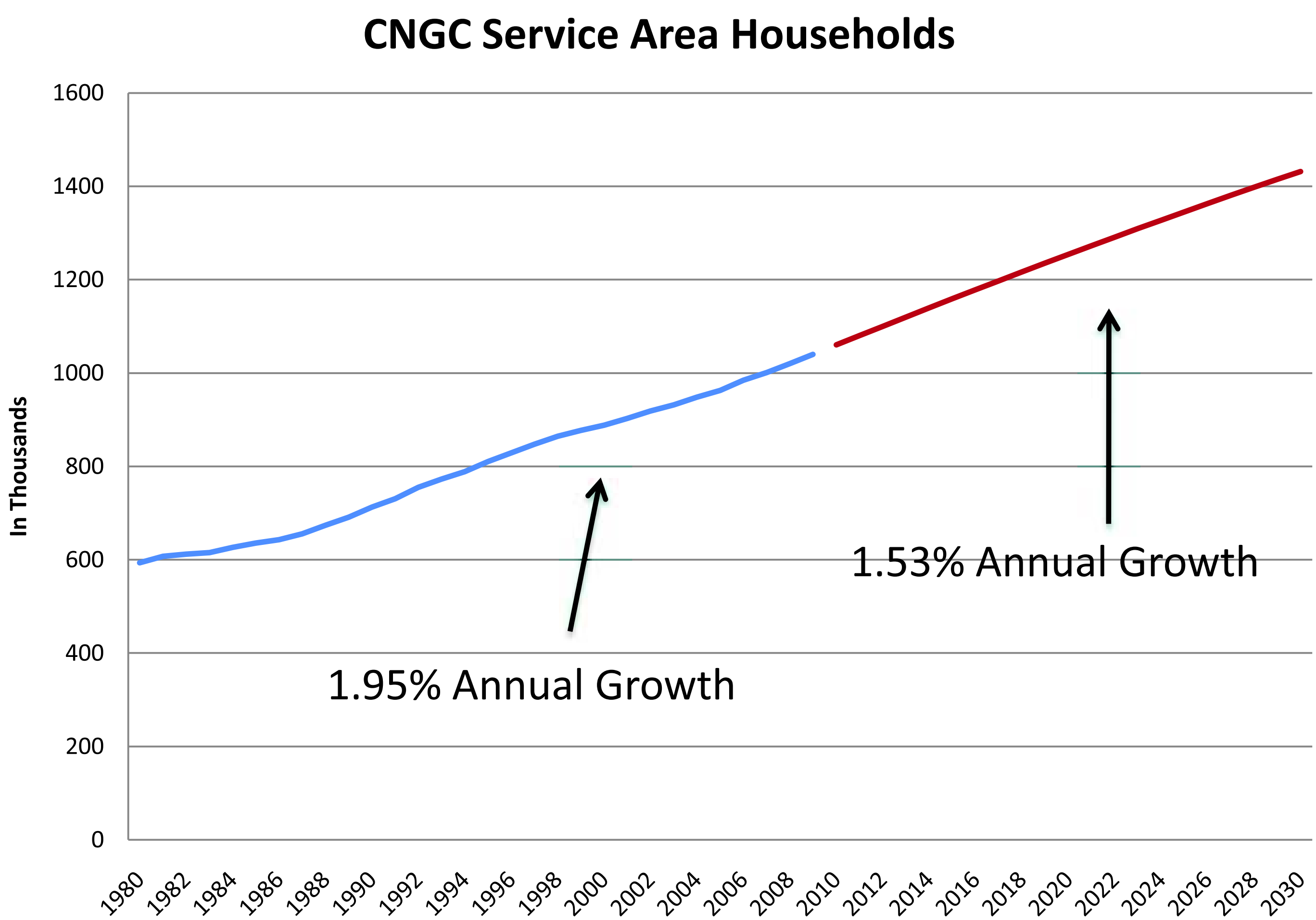
Forecasting Process



Forecasting Process

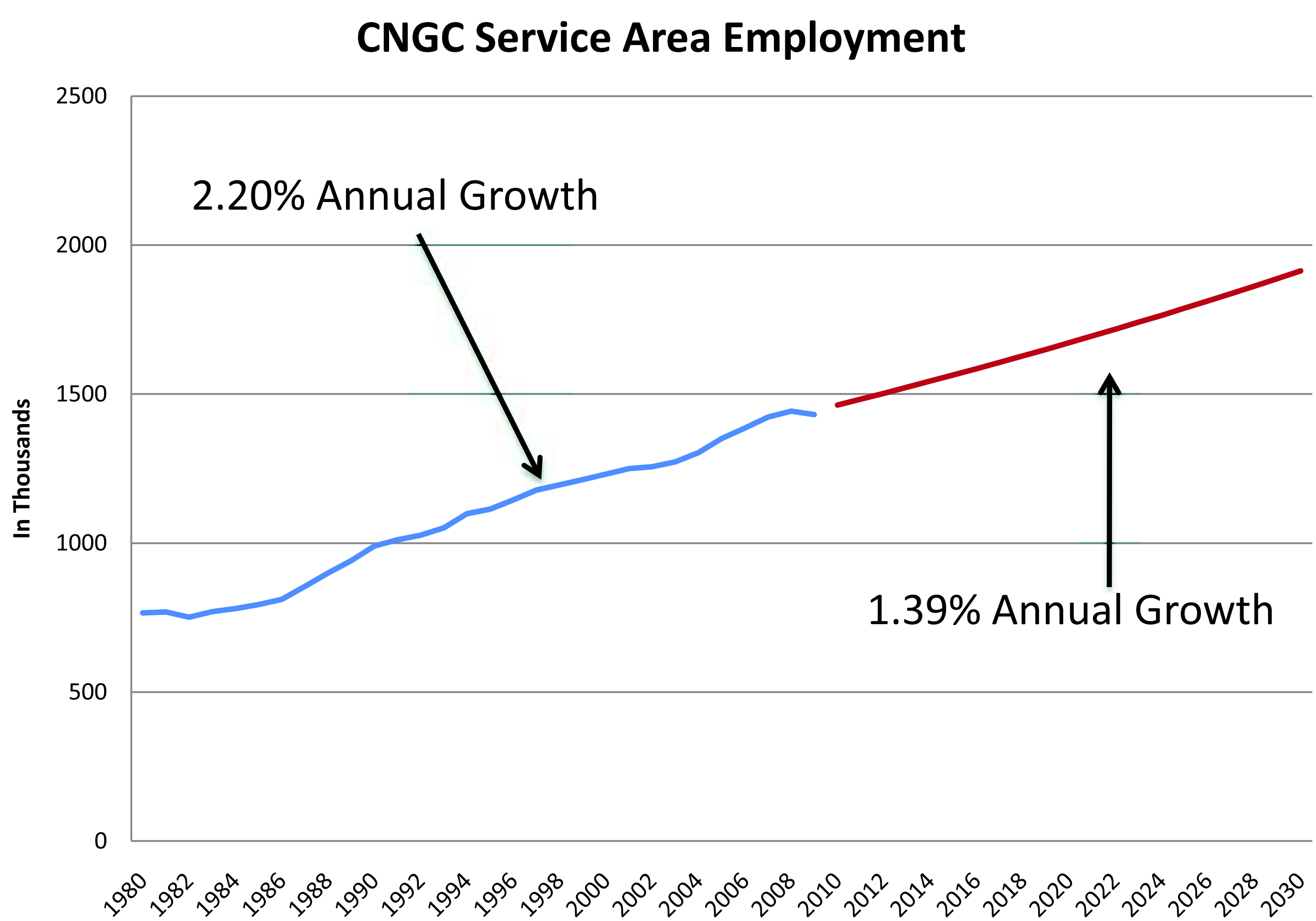


Key Assumptions



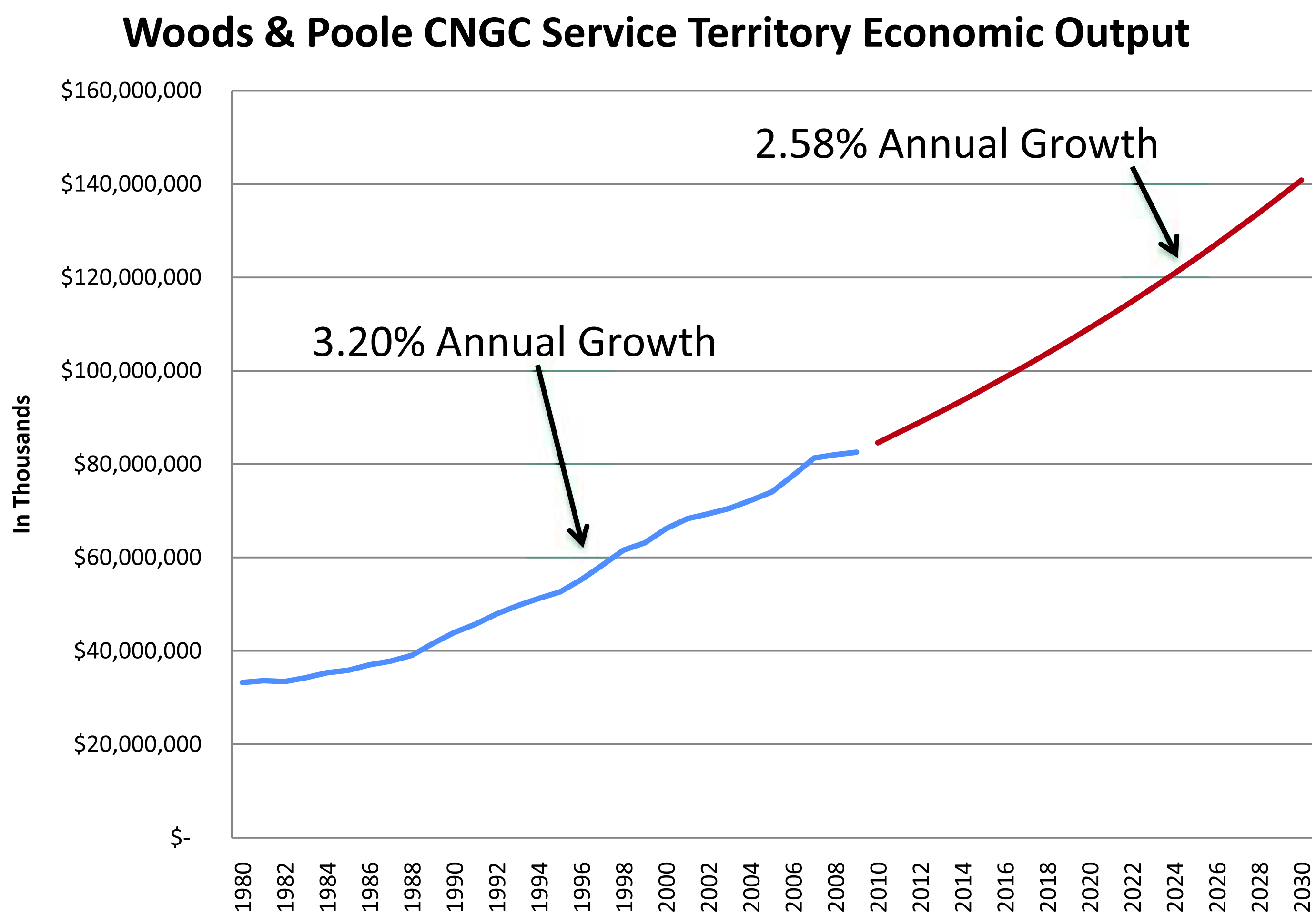
Population | Employment | Income | Interest Rates | Gas Prices | Sensitivity Analysis

Key Assumptions



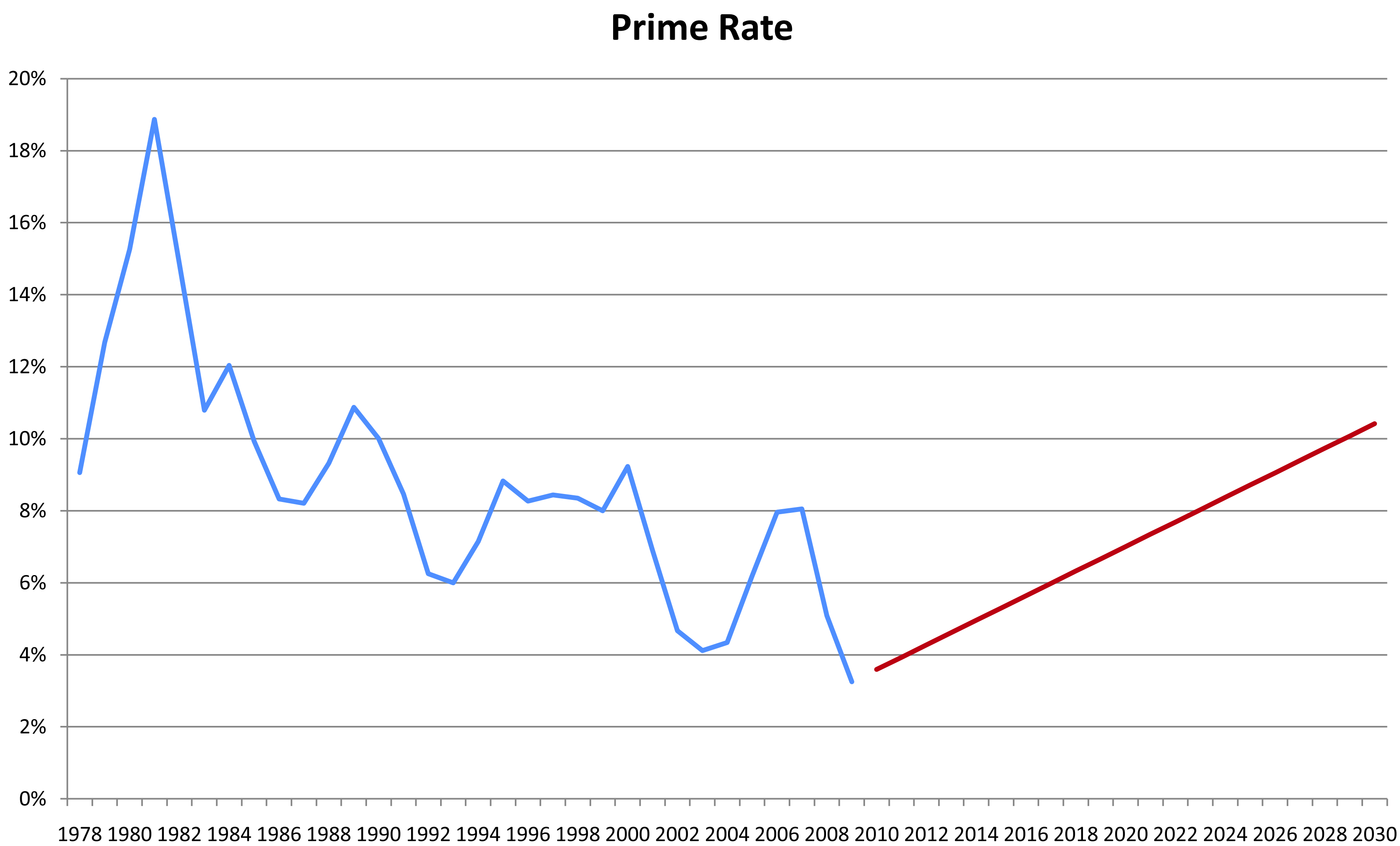
Population | Employment | Income | Interest Rates | Gas Prices | Sensitivity Analysis

Key Assumptions



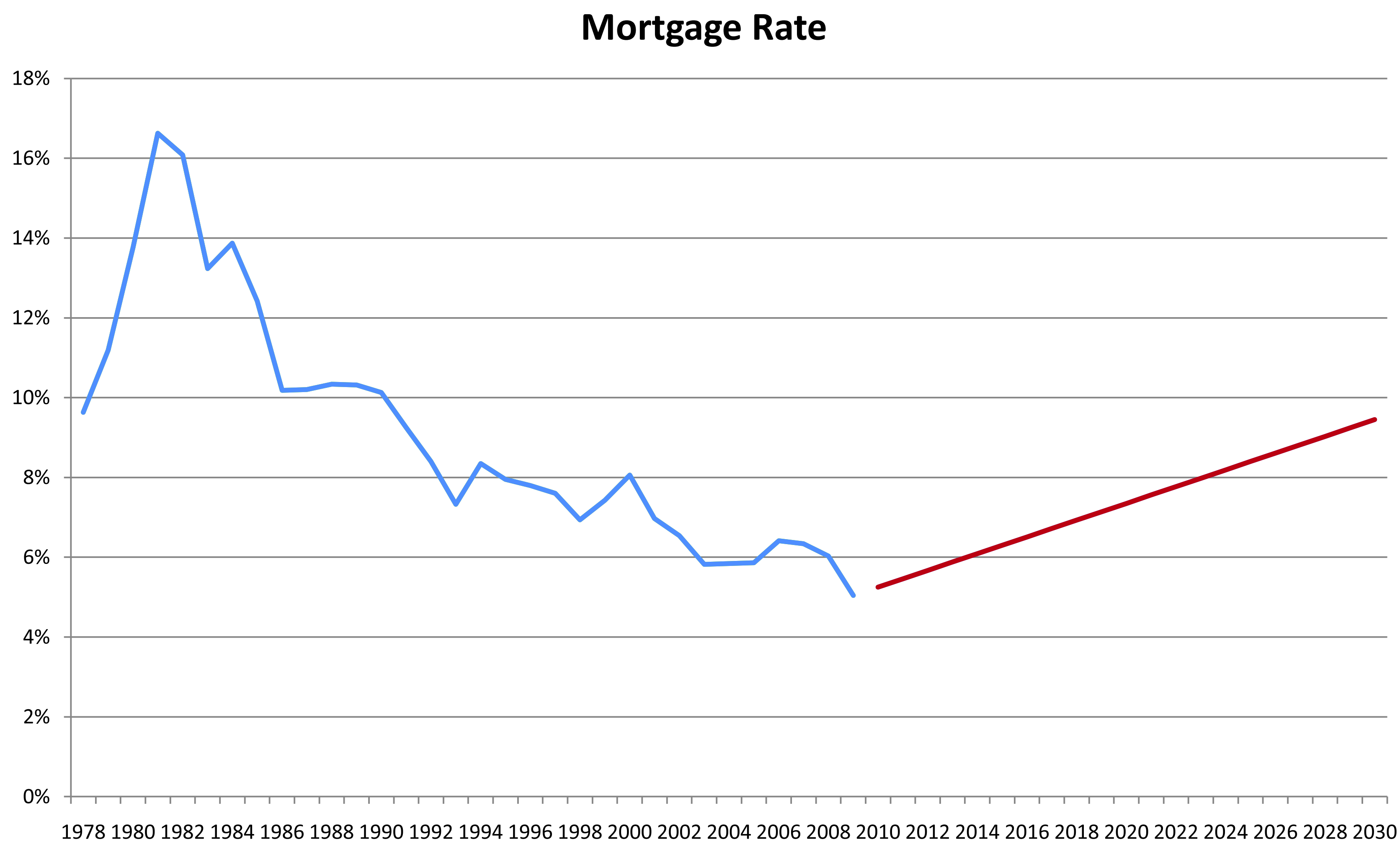
Population → Employment → Income → Interest Rates → Gas Prices → Sensitivity Analysis

Key Assumptions



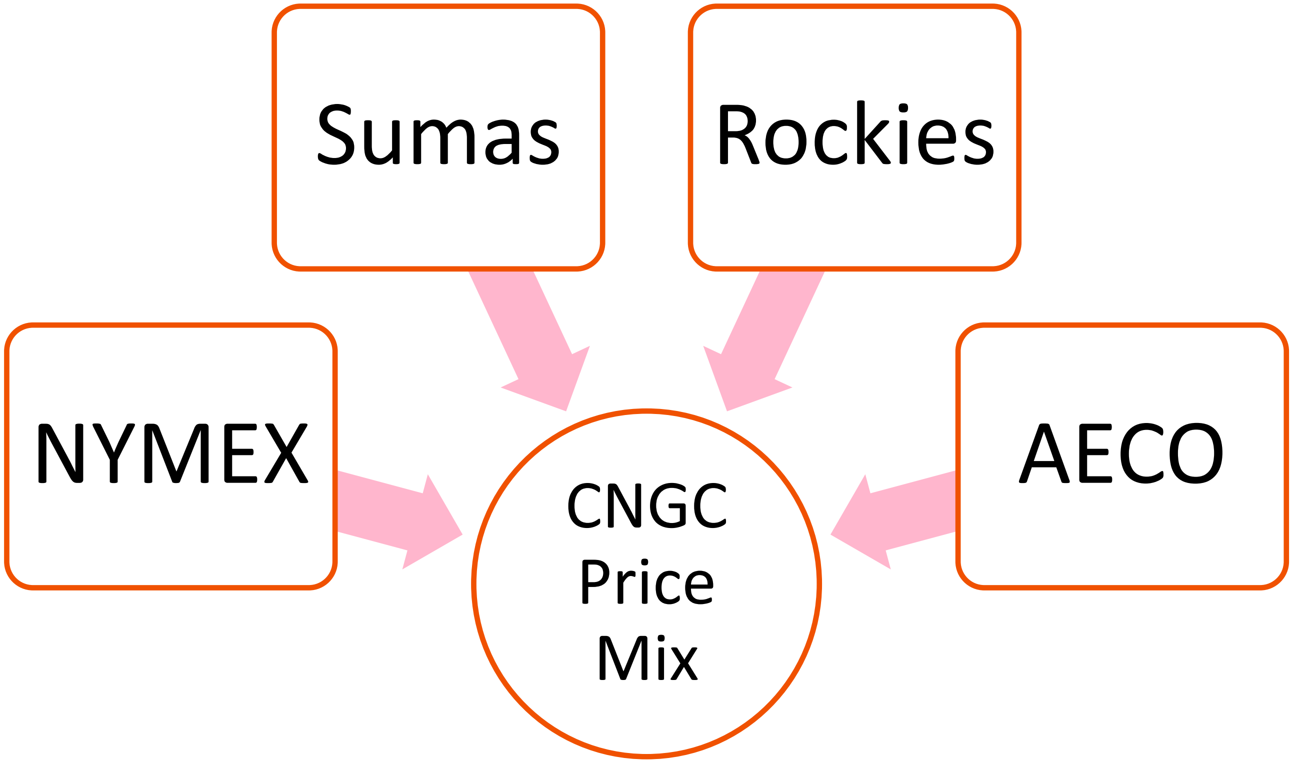
Population → Employment → Income → **Interest Rates** → Gas Prices → Sensitivity Analysis

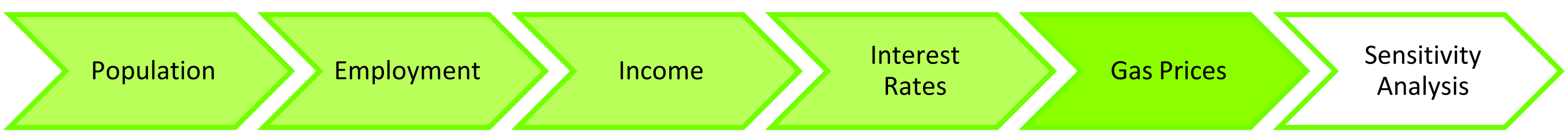
Key Assumptions



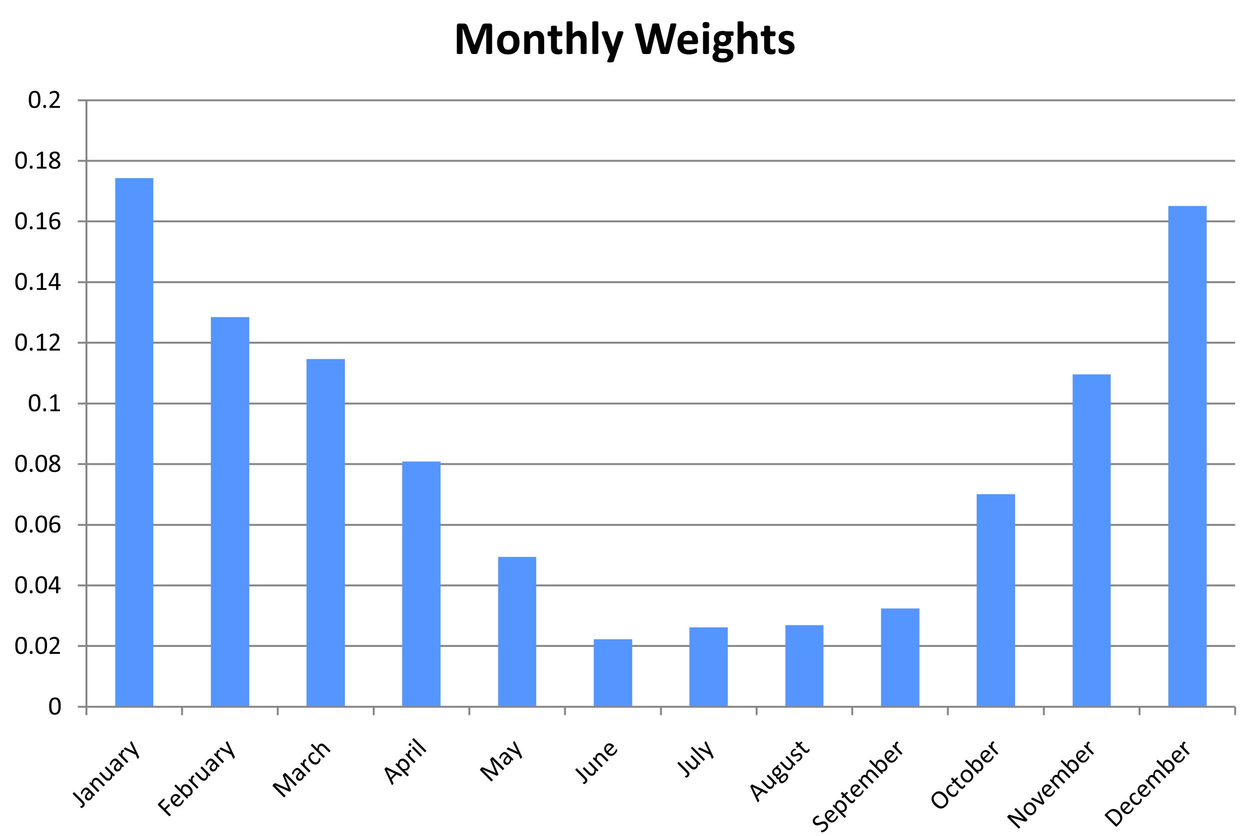
Population → Employment → Income → **Interest Rates** → Gas Prices → Sensitivity Analysis

Key Assumptions





Key Assumptions



Population → Employment → Income → Interest Rates → Gas Prices → Sensitivity Analysis

High & Low Scenarios

Cascade Natural Gas Corporation

Calculation of High and Low Scenarios

	Total Income	Growth	Ratio	Employment	Growth	Ratio	Households	Growth	Ratio	CNGC MHI	Growth	Ratio
1980	$ 33,254,841			765.279			593.614			$56,020.99		
1981	$ 33,644,380	1.17%	37%	768.969	0.48%	22%	607.68	2.37%	121%	$55,365.29	-1.17%	-96%
1982	$ 33,449,581	-0.58%	-18%	751.168	-2.31%	-105%	612.301	0.76%	39%	$54,629.31	-1.33%	-109%
1983	$ 34,258,787	2.42%	76%	[illegible]	[illegible]	110%	[illegible]	[illegible]	[illegible]	$55,707.34	[illegible]	[illegible]
1984	$ 35,289,294	3.01%	94%	[illegible]	[illegible]	66%	[illegible]	[illegible]	[illegible]	$56,308.27	[illegible]	[illegible]
1985	$ 35,822,281	1.51%	47%	[illegible]	[illegible]	75%	[illegible]	[illegible]	[illegible]	$56,341.79	[illegible]	[illegible]
1986	$ 37,036,868	3.39%	106%	811.027	2.26%	103%	643.213	1.17%	60%	$57,581.03	2.20%	180%
1987	$ 37,826,980	2.13%	67%	854.606	5.37%	245%	655.191	1.86%	95%	$57,734.28	0.27%	22%
1988	$ 39,042,205	3.21%	100%	899.576	5.26%	240%	674.009	2.87%	147%	$57,925.35	0.33%	27%
1989	$ 41,581,885	6.50%	203%	940.75	4.58%	208%	691.398	2.58%	132%	$60,141.75	3.83%	314%
1990	$ 43,967,153	5.74%	179%	990.704	5.31%	242%	713.113	3.14%	161%	$61,655.24	2.52%	206%
1991	$ 45,717,784	3.98%	124%	1011.123	2.06%	94%	730.594	2.45%	125%	$62,576.18	1.49%	122%
1992	$ 47,939,210	4.86%	152%	[illegible]	[illegible]	69%	[illegible]	[illegible]	[illegible]	$63,462.02	[illegible]	[illegible]
1993	$ 49,705,969	3.69%	115%	[illegible]	[illegible]	109%	[illegible]	[illegible]	[illegible]	$64,309.67	[illegible]	[illegible]
1994	$ 51,241,927	3.09%	97%	1098.497	4.53%	206%	788.633	2.03%	104%	$64,975.63	1.04%	85%
1995	$ 52,638,810	2.73%	85%	1113.879	1.40%	64%	810.222	2.74%	140%	$64,968.38	-0.01%	-1%
1996	$ 55,253,684	4.97%	155%	1144.441	2.74%	125%	829.164	2.34%	120%	$66,637.82	2.57%	211%
1997	$ 58,361,667	5.62%	176%	1177.538	2.89%	132%	847.126	2.17%	111%	$68,893.73	3.39%	278%
1998	$ 61,557,397	5.48%	171%	1195.282	1.51%	69%	864.636	2.07%	106%	$71,194.58	3.34%	274%
1999	$ 63,129,868	2.55%	80%	1212.492	1.44%	66%	877.349	1.47%	75%	$71,955.25	1.07%	88%
2000	$ 66,152,723	4.79%	150%	1231.369	1.56%	71%	888.232	1.24%	63%	$74,476.85	3.50%	287%
2001	$ 68,336,841	3.30%	103%	1249.618	1.48%	68%	902.629	1.62%	83%	$75,708.67	1.65%	136%
2002	$ 69,326,847	1.45%	45%	1255.866	0.50%	23%	918.551	1.76%	90%	$75,474.14	-0.31%	-25%
2003	$ 70,509,404	1.71%	53%	1272.666	1.34%	61%	932.02	1.47%	75%	$75,652.24	0.24%	19%
2004	$ 72,199,192	2.40%	75%	1303.222	2.40%	109%	948.039	1.72%	88%	$76,156.35	0.67%	55%
2005	$ 74,076,802	2.60%	81%	1350.557	3.63%	165%	963.082	1.59%	81%	$76,916.40	1.00%	82%
2006	$ [illegible]	4.78%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2007	$ [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2008	$ [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2009	$ [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Growth rates are 120% of average. Use 120% of W&P as the high for employment.

Growth rates are 95% of average. Use 95% of W&P as the high for employment.

Growth rates are 84% of average. Use 84% of W&P as the high for employment.

Growth rates are 77% of average.

Growth rates are 114% of average.

Growth rates are 157% of average.

Population → Employment → Income → Interest Rates → Gas Prices → Sensitivity Analysis

High & Low Scenarios

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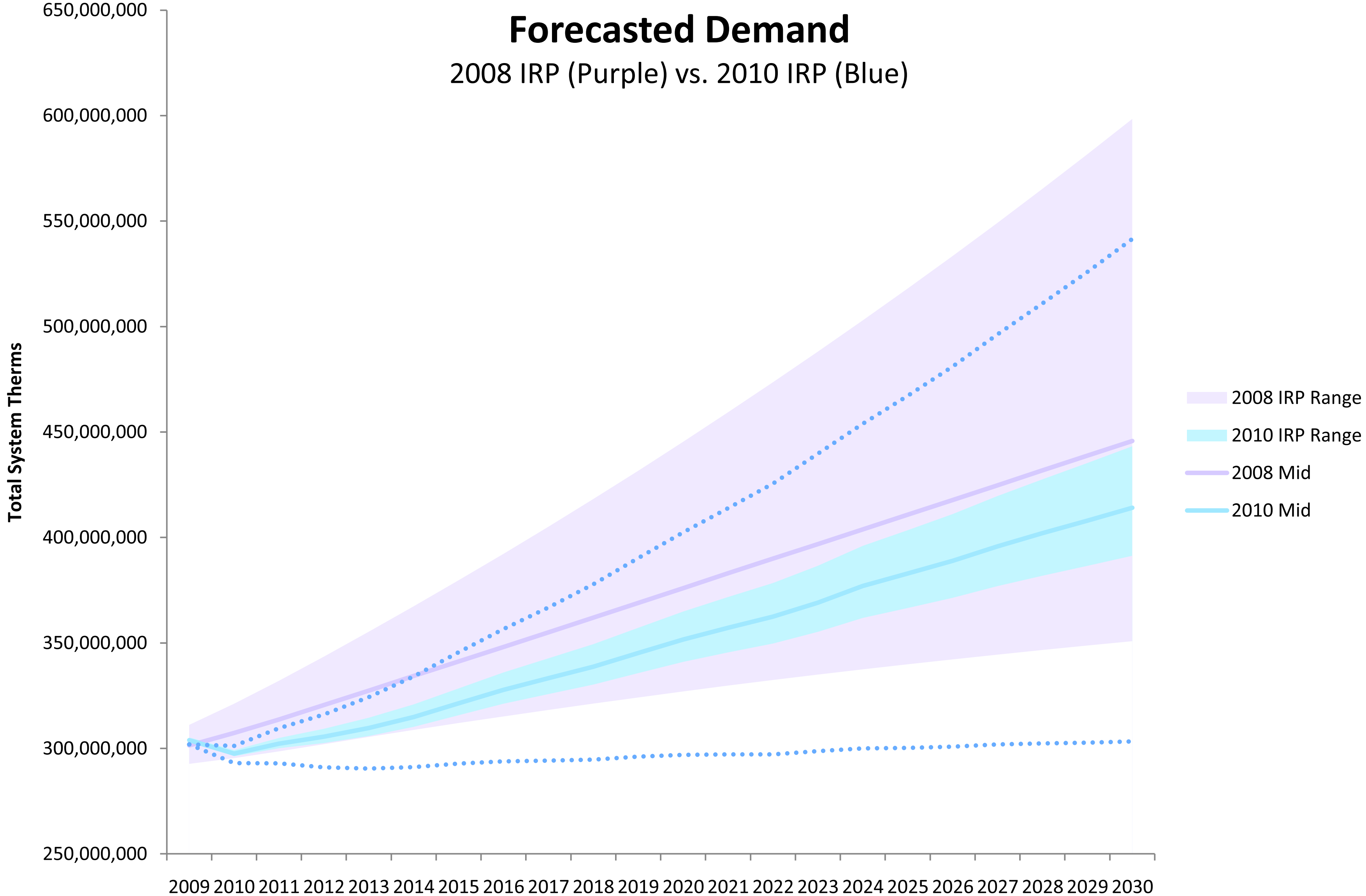
Scenario	Area	Annual Growth 1998 - 2008
Lowest Growth:	Michigan Public Service Commission	0.284%
Highest Growth:	Utah – Questar Gas	3.02%
Alternate Highest:	Cascade	3.09%

Population → Employment → Income → Interest Rates → Gas Prices → Sensitivity Analysis

RESULTS



Forecasted Demand
2008 IRP (Purple) vs. 2010 IRP (Blue)
Total System Therms
650,000,000
600,000,000
550,000,000
500,000,000
450,000,000
400,000,000
350,000,000
300,000,000
250,000,000
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
2008 IRP Range
2010 IRP Range
2008 Mid
2010 Mid

RECESSION

Unemployment

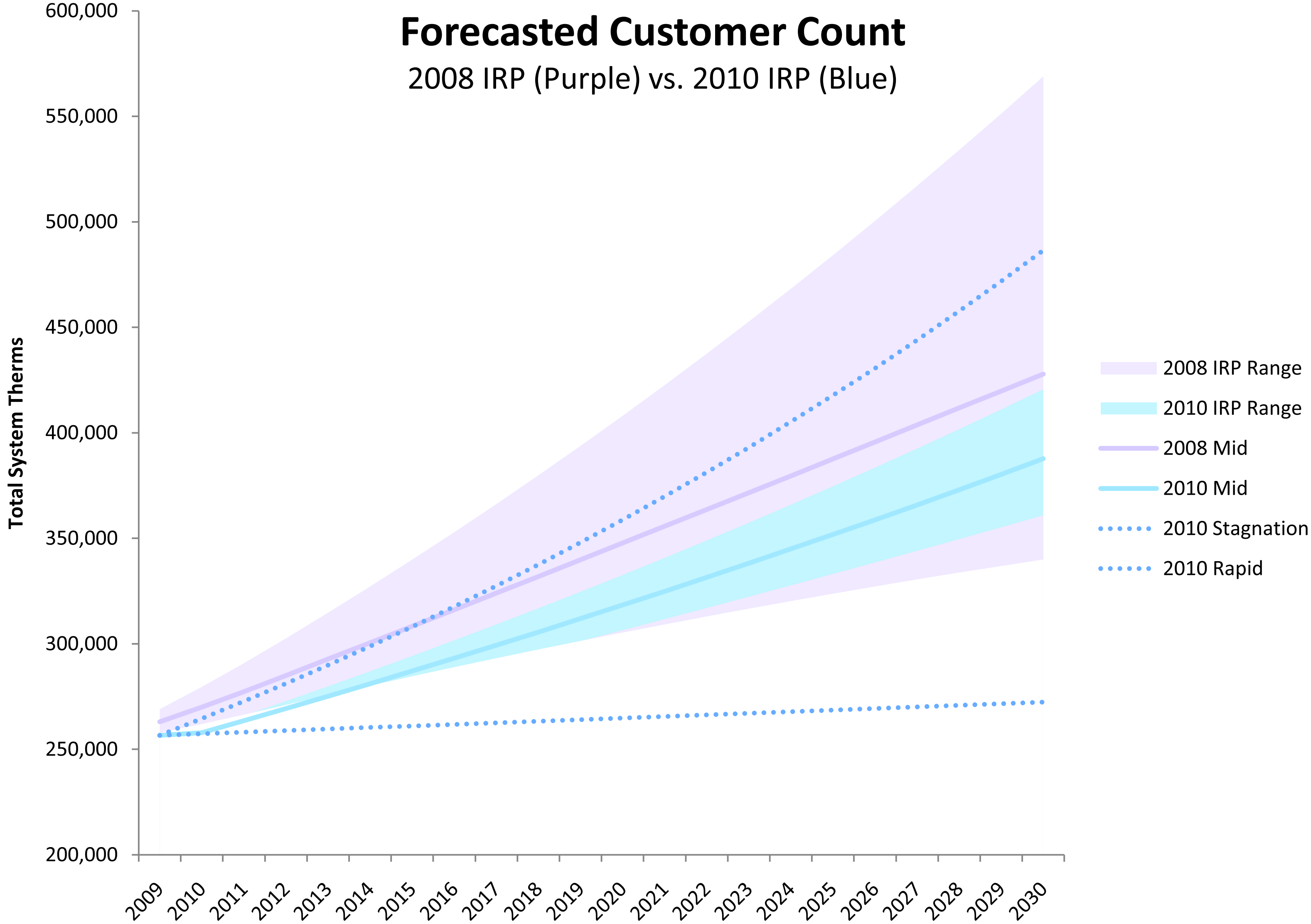
		Rate	Residential Customers
National		9.7%	
Washington		9.2%	
Bellingham		8.3%	40,169
Bremerton		7.6%	27,781
Kennewick		8.1%	19,214
Longview		13.3%	2,590
Mt. Vernon		10.8%	35,394
Yakima		11.0%	19,070
Wenatchee		9.4%	3,406
CNGC		9.20%	

RECESSION

Employment Growth

	Low	Med	High
CNGC	-0.422%	0.089%	0.534%
Standard & Poor’s		0.039%	
Goldman Sachs		0.049%	
WSJ Survey Average		**0.089%**	
Bank of America		0.096%	
JP Morgan		0.116%	
RBS		0.154%	

RESULTS

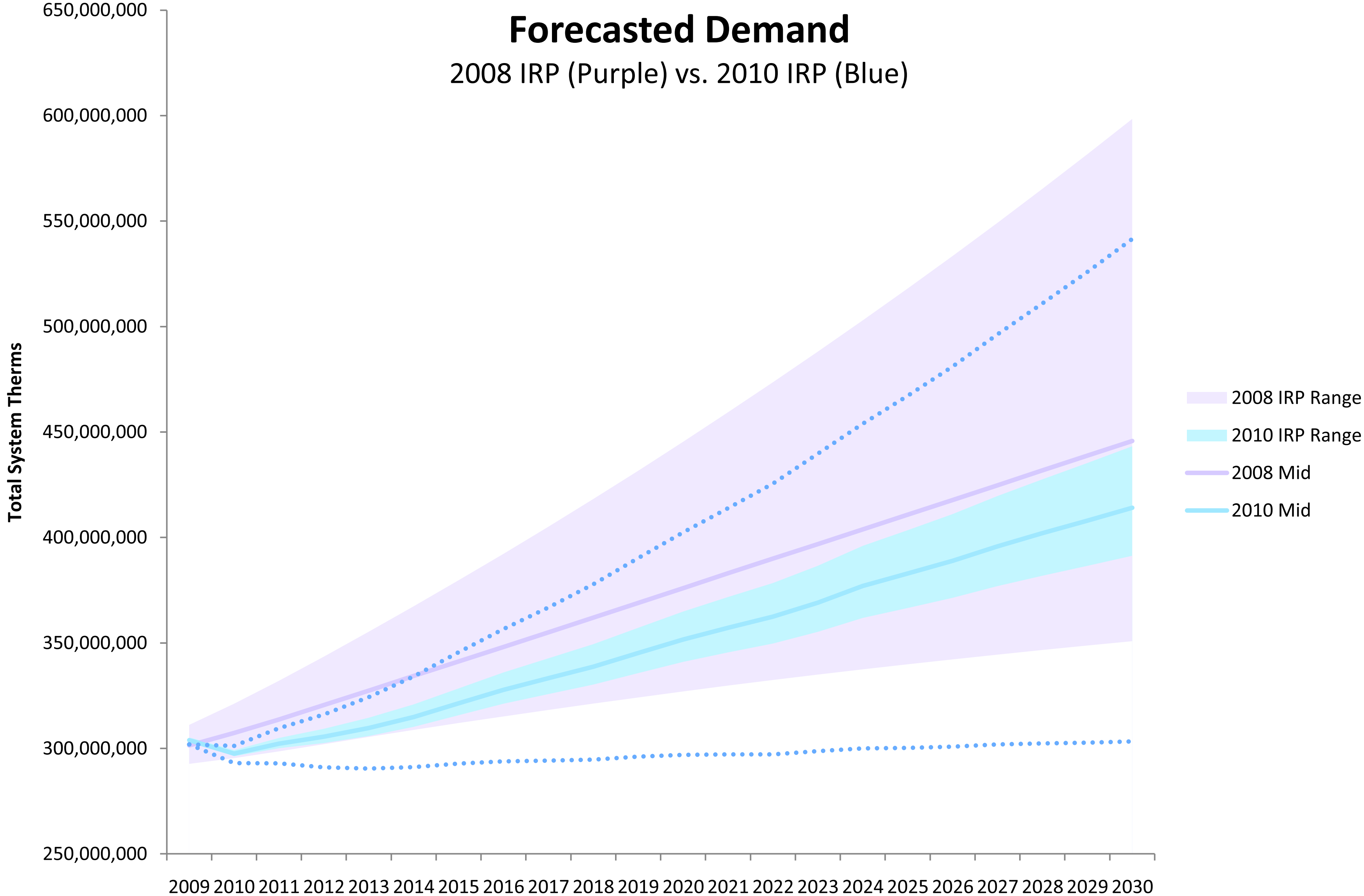


Forecasted Customer Count
2008 IRP (Purple) vs. 2010 IRP (Blue)
Total System Therms
600,000
550,000
500,000
450,000
400,000
350,000
300,000
250,000
200,000
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2008 IRP Range
2010 IRP Range
2008 Mid
2010 Mid
2010 Stagnation
2010 Rapid

RESULTS

Forecasted Annual Throughput					
		Therms		Growth	
Above/Below System Average		2010	2030	30-Year	Annualized
⇩	Aberdeen	9,409,815	10,236,640	8.8%	0.42%
⇨	Bellingham	51,678,386	69,420,450	34.3%	1.49%
⇧	Bremerton	29,583,574	47,902,190	61.9%	2.44%
⇧	Kennewick	25,252,682	48,537,914	92.2%	3.32%
⇨	Longview	7,254,439	8,232,010	13.5%	0.63%
⇨	Moses Lake	4,046,098	4,807,217	18.8%	0.87%
⇨	Mount Vernon	42,020,214	60,412,599	43.8%	1.83%
⇩	Sunnyside	9,192,796	9,388,827	2.1%	0.11%
⇨	Walla Walla	11,173,305	12,327,626	10.3%	0.49%
⇩	Wenatchee	5,503,296	3,821,774	30.6%	1.81%
⇨	Yakima	28,682,954	32,288,833	12.6%	0.59%
⇩	Baker	4,064,606	4,070,715	0.2%	0.01%
⇧	Bend	49,302,163	79,451,025	61.2%	2.41%
⇩	Ontario	5,039,139	5,267,725	4.5%	0.22%
⇨	Pendleton	13,329,645	15,931,766	19.5%	0.90%
	Washington	223,797,557	307,376,079	37.3%	1.60%
	Oregon	71,735,554	104,721,232	46.0%	1.91%
	System	295,533,111	412,097,311	39.4%	1.68%

RESULTS



Forecasted Demand
2008 IRP (Purple) vs. 2010 IRP (Blue)
Total System Therms
650,000,000
600,000,000
550,000,000
500,000,000
450,000,000
400,000,000
350,000,000
300,000,000
250,000,000
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
2008 IRP Range
2010 IRP Range
2008 Mid
2010 Mid

Next Steps-Distribution Modeling

- **Evaluate System capabilities under IRP demand forecast**
- **Estimate Reinforcements needed to support forecasted peak day requirements**

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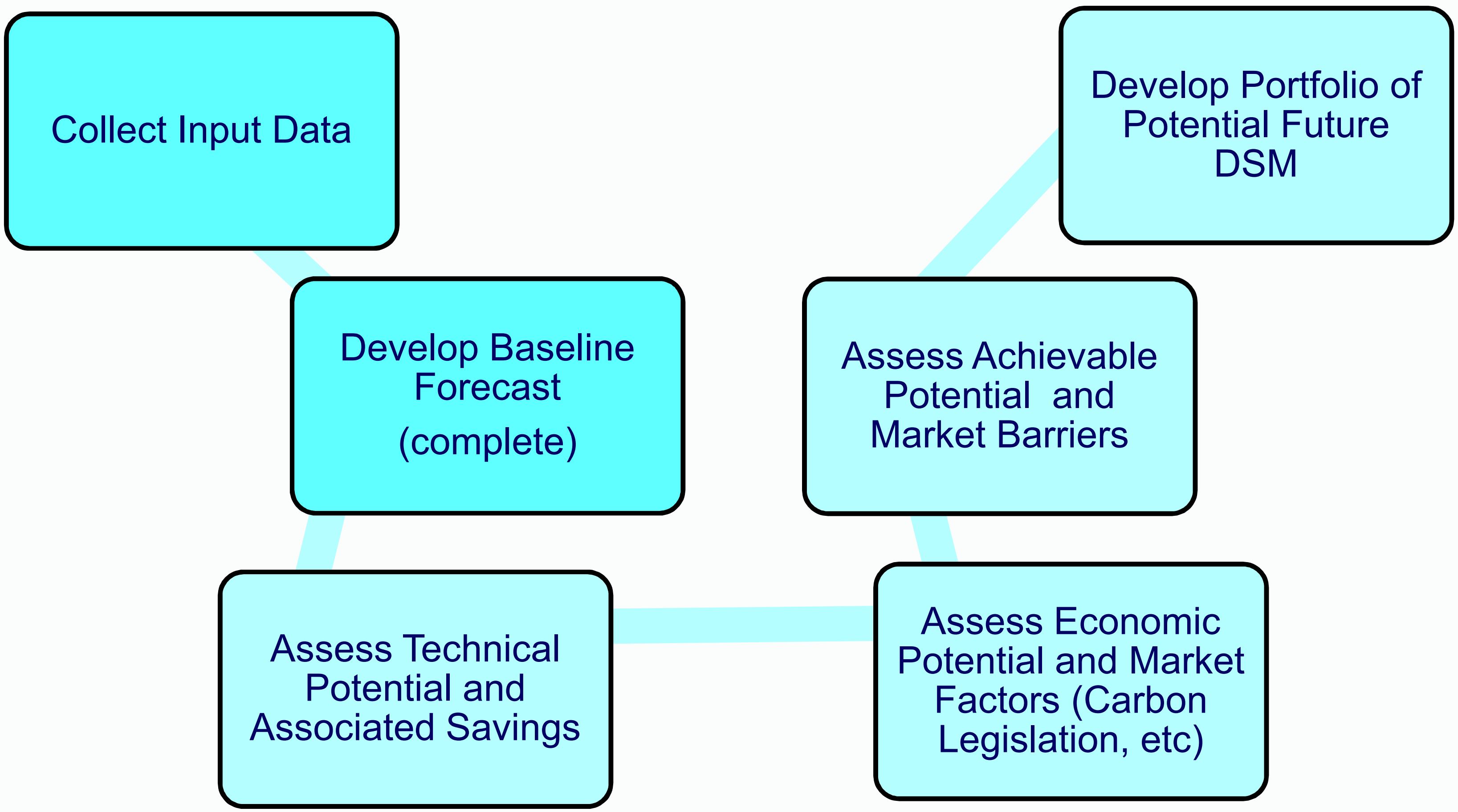
Next Steps-Conservation Potential

Conservation Analysis Process



Next Steps – Supply Side & Integration Modeling

- **Identify Capacity Shortfalls**
  - **Determine magnitude of shortfall (degree day coverage)**
- **Begin Sendout modeling and Weather sensitivity impact to Forecast**
- **Identify/Evaluate solutions**

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Adjourn

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2010 Integrated Resource Plan

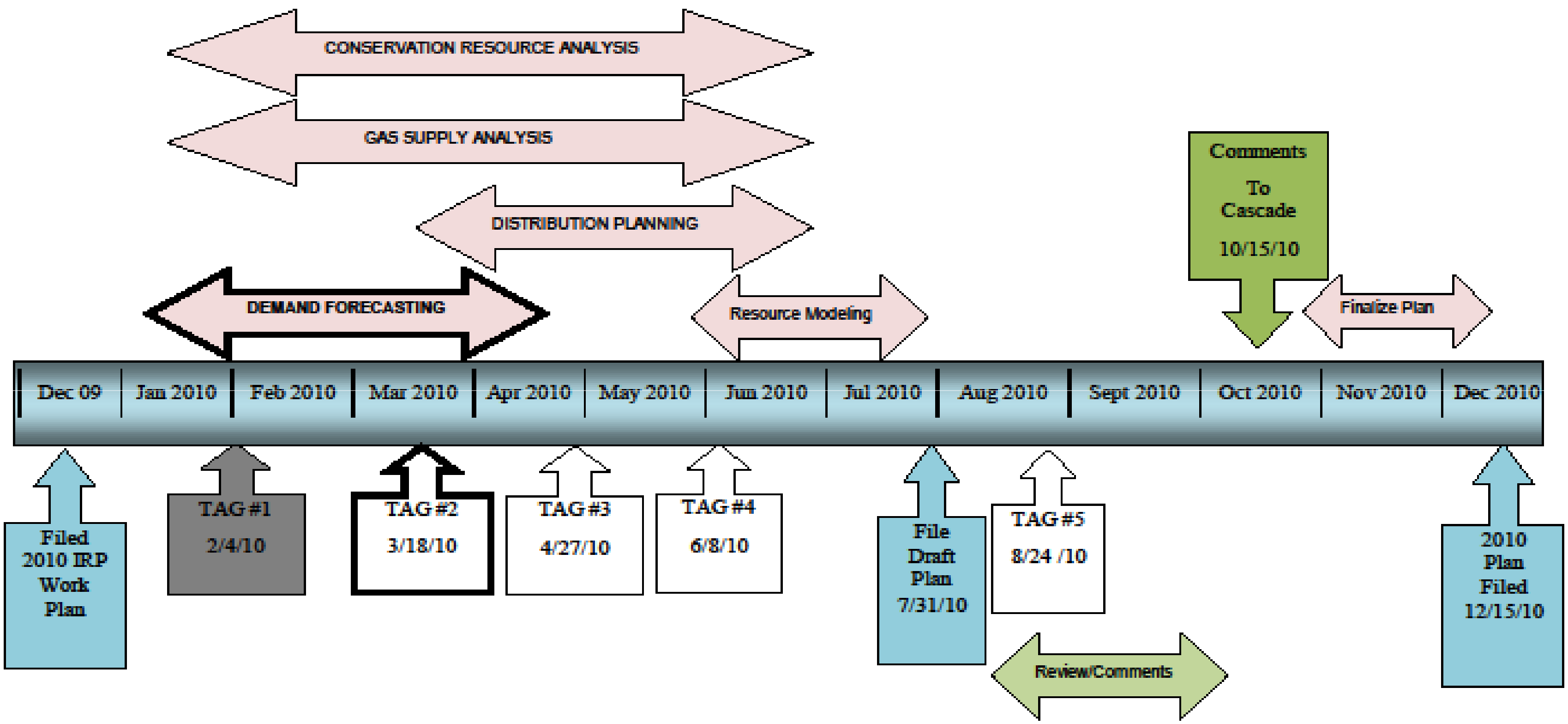
Technical Advisory Group Meeting

April 27, 2010

Agenda

- Introductions
- 2010 IRP Workplan Overview
- Peak Day Forecasting
- Distribution System Planning
- Capacity Analysis
- Integration Modeling – Inputs & Preliminary Analysis

2010 IRP Workplan



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Peak Day Forecast

- Peak day forecast based on a 61degree day (0 degrees Fahrenheit average temperature) for design weather conditions

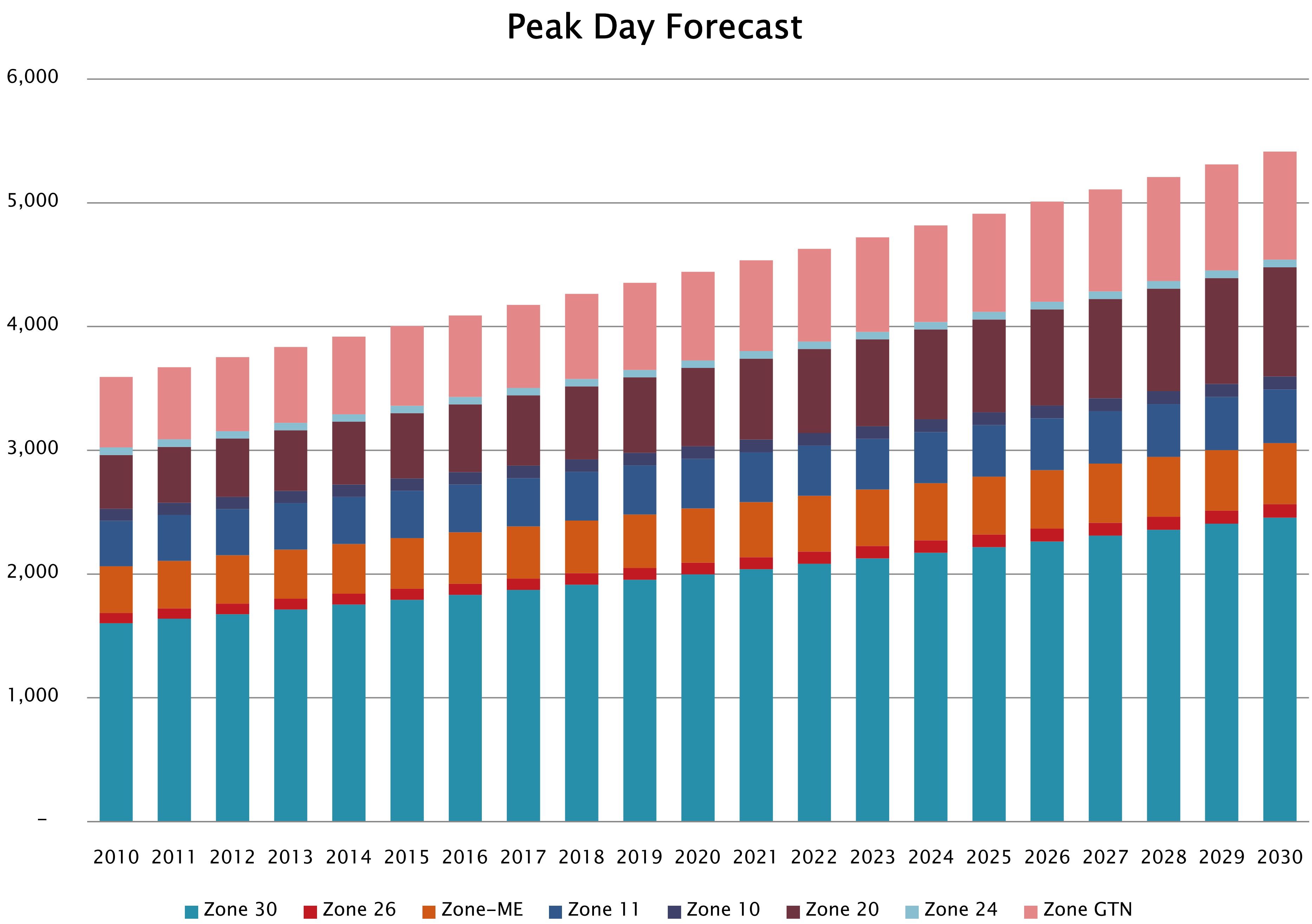
System Average Degree Days	Date / Year
65	1968
63	1950
61	1964, 1957, 1983,**1990**
60	1950, 1957, 1968, 1990
59	1950, 1972, 1979, 1983, 1989, 1990
58	1950, 1979
57	1957,1964, 1972, 1990
56	1963, 1982, 1983, **2004**

Peak Day Forecast (cont.)

- Gas use on January 5, 2004 represent Cascade's best peak day demand approximation in recent history (56 degree day).

- Therm consumption was adjusted to reflect estimated consumption during a System wide 61 degree day.

- Peak day therm consumption developed for each area and escalated each year by the customer growth rate.


Peak Day Forecast
6,000
5,000
4,000
3,000
2,000
1,000
–
2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Zone 30 Zone 26 Zone-ME Zone 11 Zone 10 Zone 20 Zone 24 Zone GTN

Distribution System Planning to Support IRP Growth

Cascade Natural Gas Corp.

4/27/10

Distribution System Modelling

- CNG maintains two models of each distribution system
  - Calibrated Model: Each model is calibrated annually to the peak hour which occurred over the past year
  - Design Day Model: A second model is created by increasing the Calibrated Model loads to simulate the coldest day we plan for

Design Day Model Function

- Evaluate system for capability to support new customers
- Plan necessary reinforcements to support system on peak winter days
- IRP Planning

Modelling for the IRP

- Loads in Design Day models are increased per the IRP forecast (medium scenario)
- Model is examined for areas of low pressure
- Footage and diameter of pipe needed to correct low pressure areas are estimated
- Average total cost of pipe installation (by diameter) is used to predict total cost of reinforcements

System Model Examples

- Kennewick Distribution System Model
  (Demonstration)

Reinforcement Planning

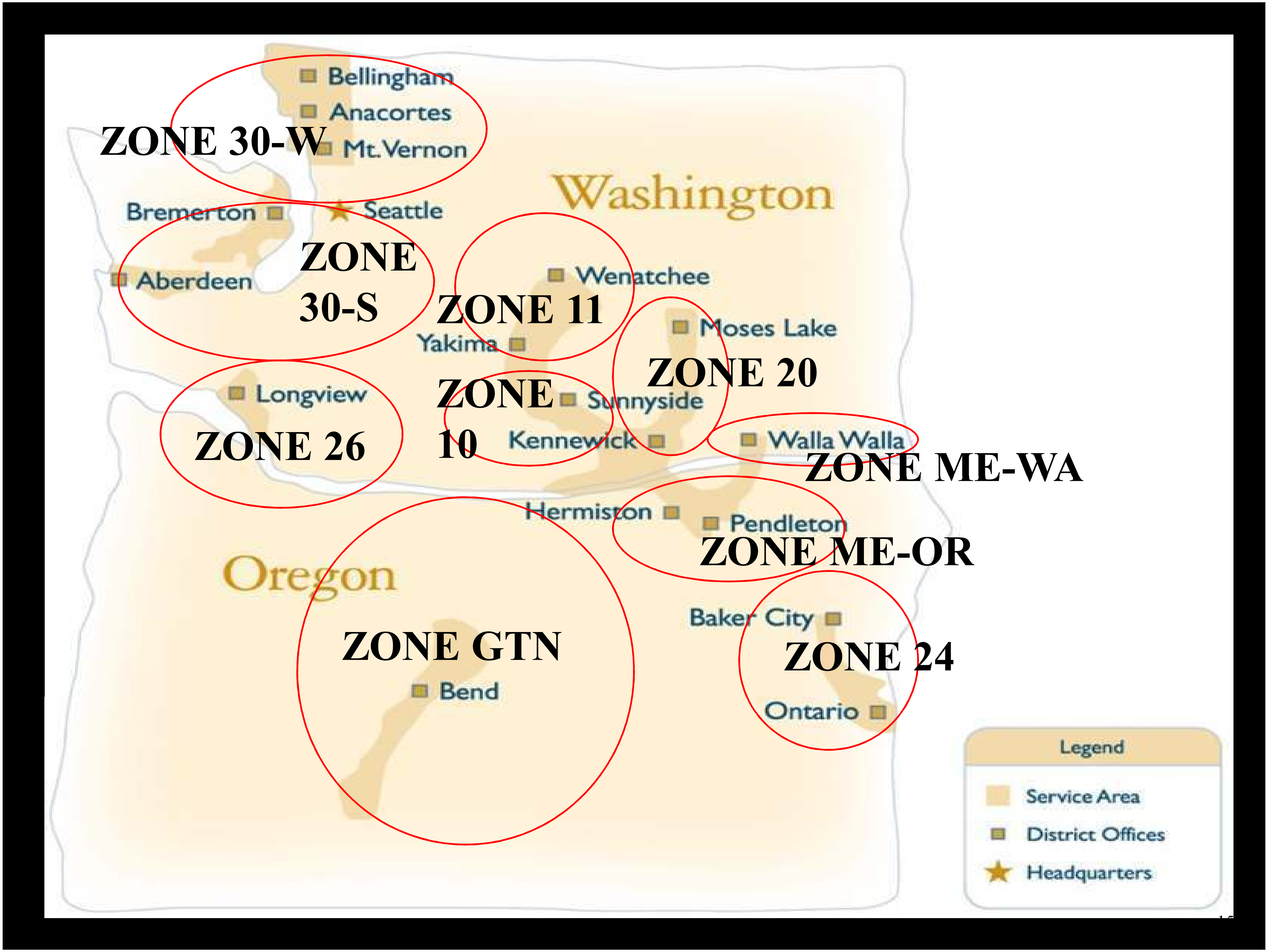
- Is the predicted pressure problem in a small localized area?

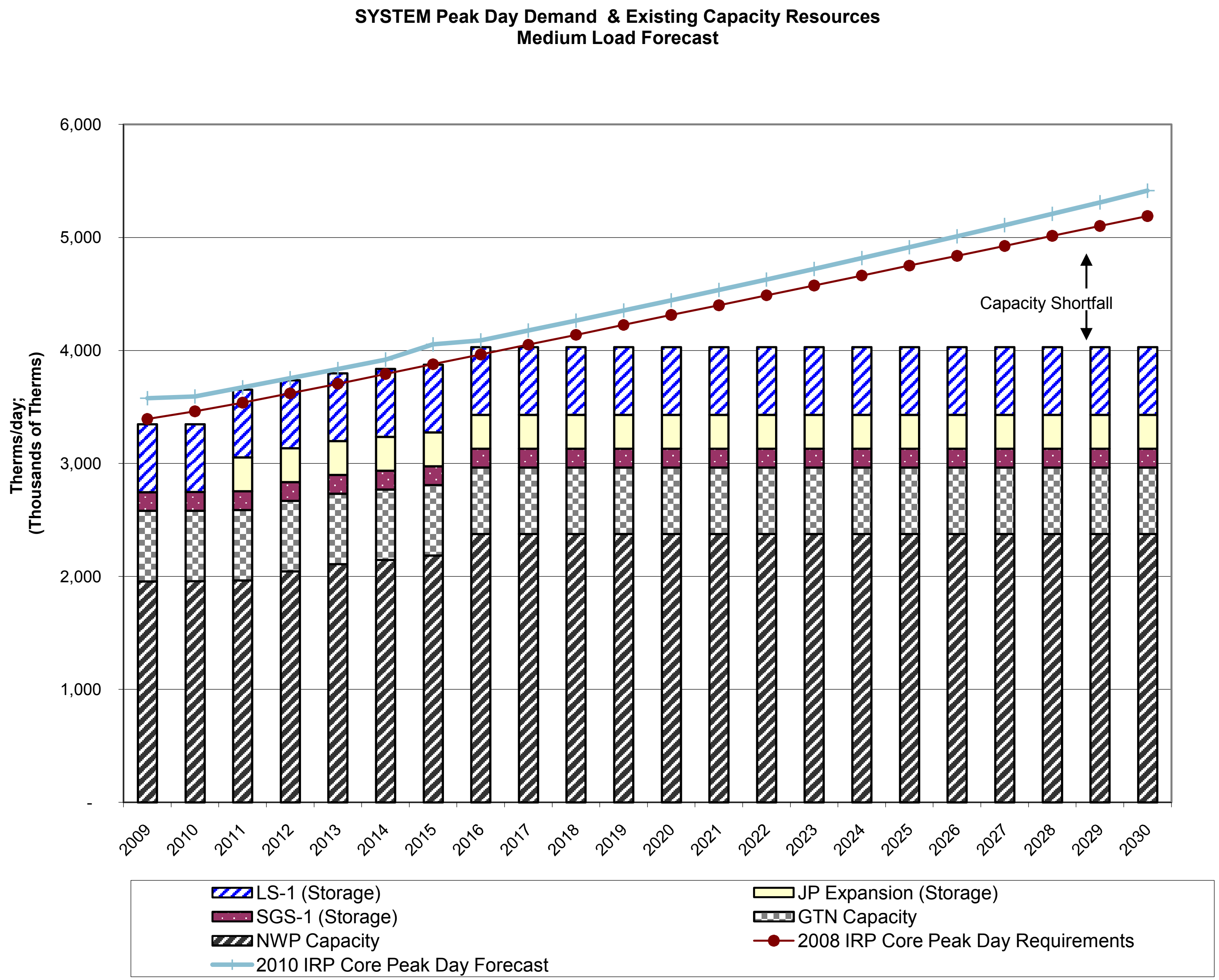
- Is the predicted pressure problem related to problems with the high-pressure system?

QUESTIONS?

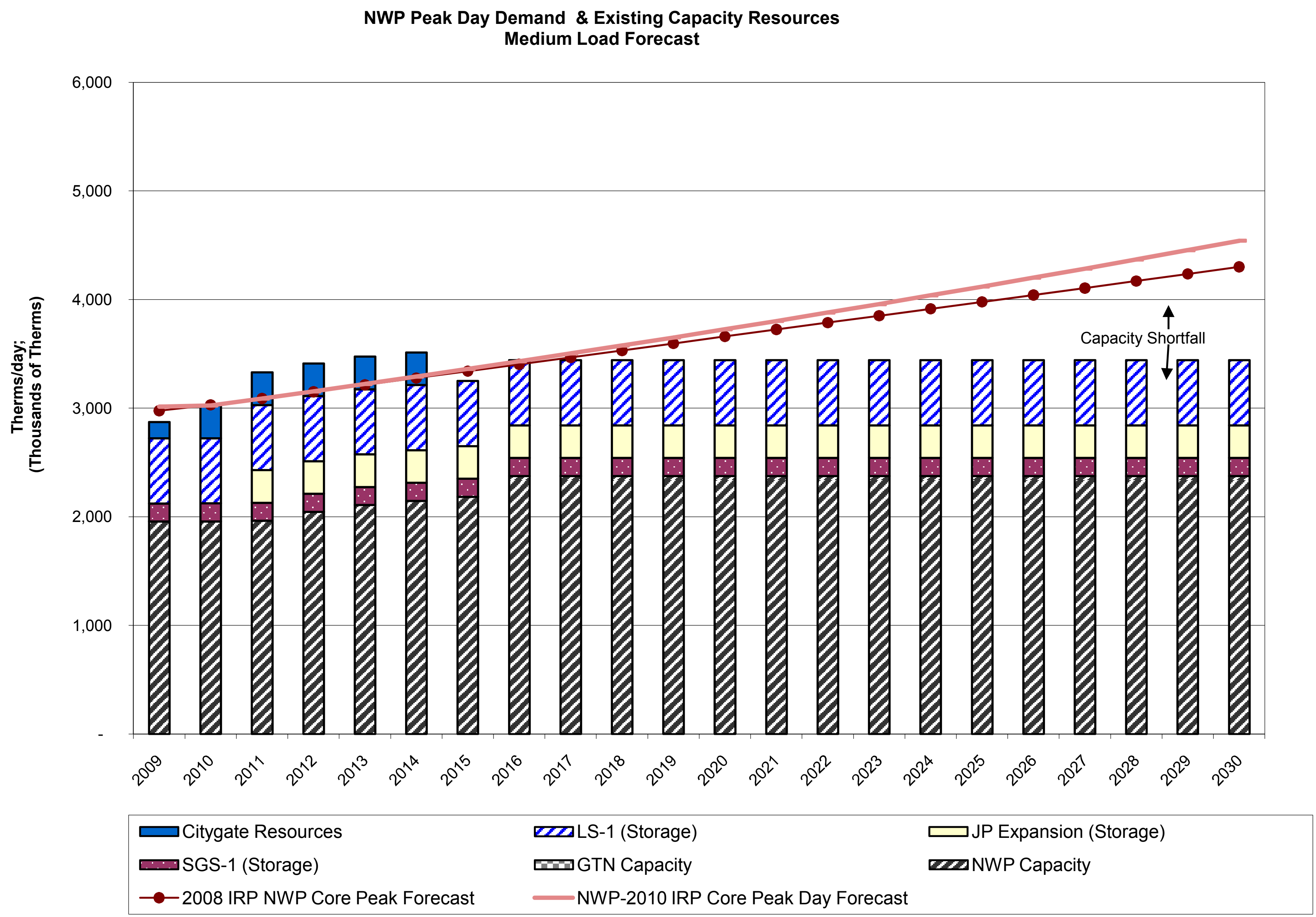
Capacity Analysis

- Overall Pipeline Receipt Capabilities vs Peak Day Demand
- Delivery Capabilities at the Gate (MDDO's)
- Distribution System Needs

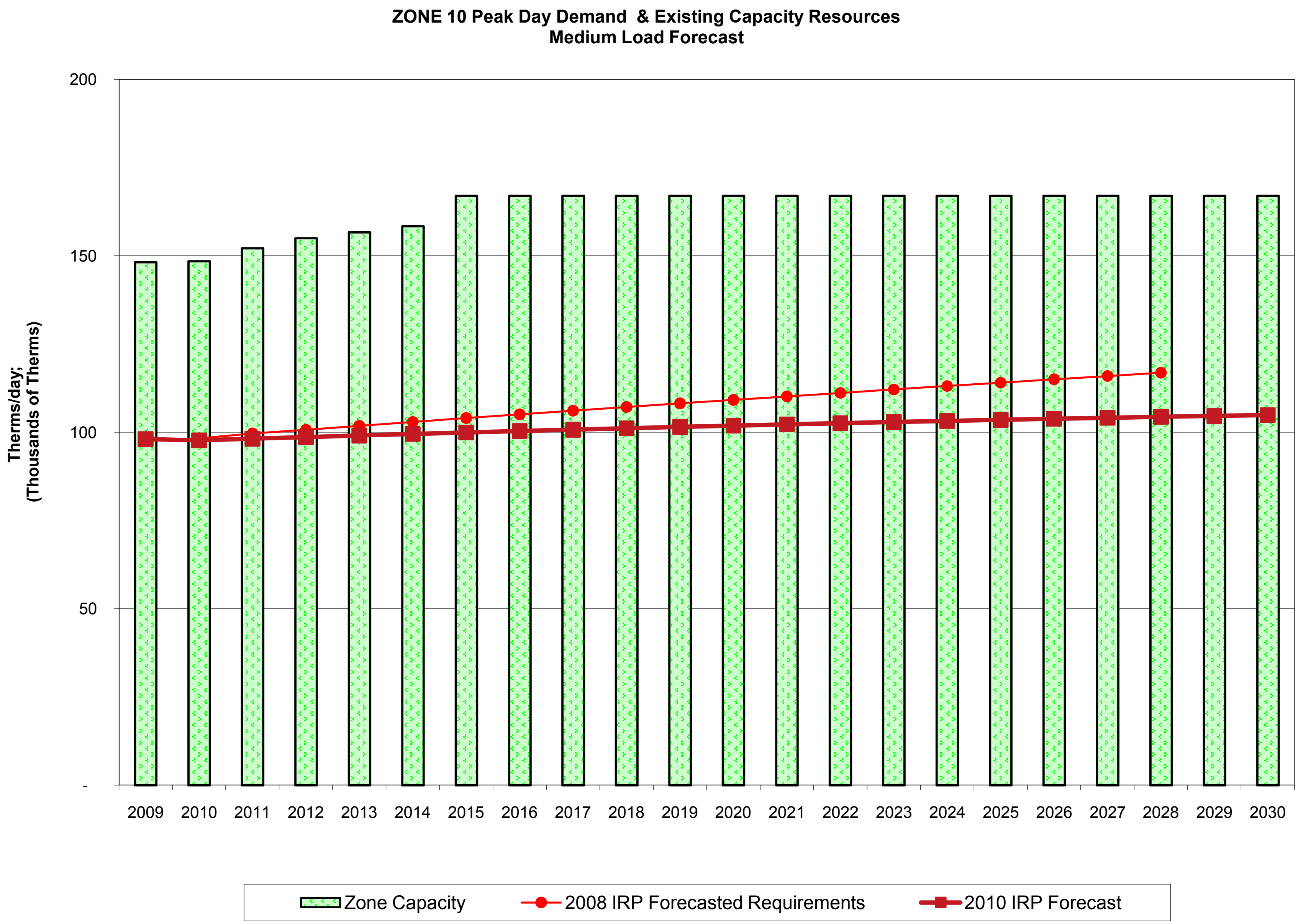

Washington
Oregon
Bellingham
Anacortes
Mt.Vernon
Bremerton
Seattle
Aberdeen
Wenatchee
Moses Lake
Yakima
Longview
Sunnyside
Kennewick
Walla Walla
Hermiston
Pendleton
Baker City
Bend
Ontario
ZONE 30-W
ZONE 30-S
ZONE 11
ZONE 20
ZONE 10
ZONE 26
ZONE ME-WA
ZONE ME-OR
ZONE GTN
ZONE 24
Legend
Service Area
District Offices
Headquarters



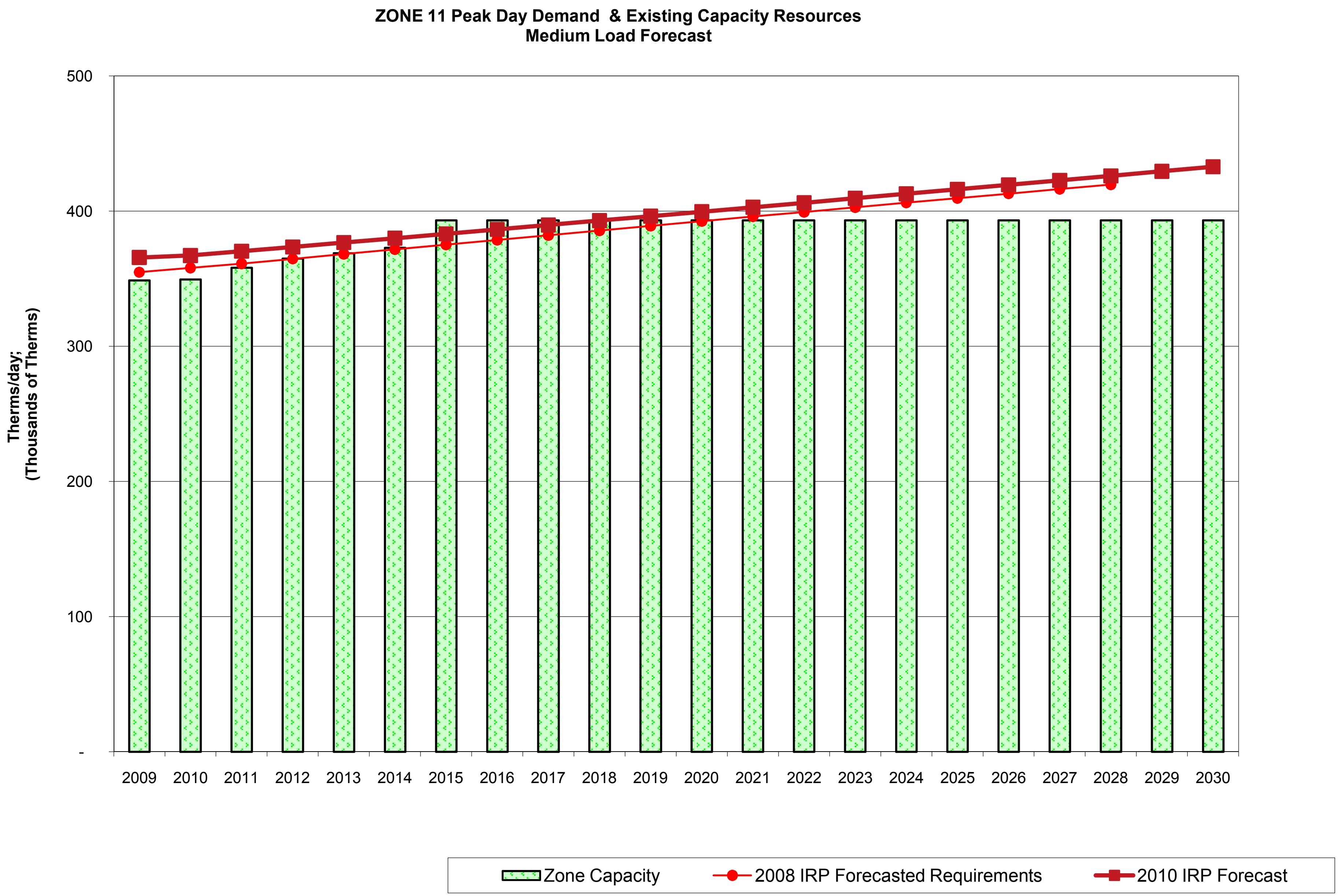
Note: WGPW Capacity is net of Non-Core primary term capacity requirements



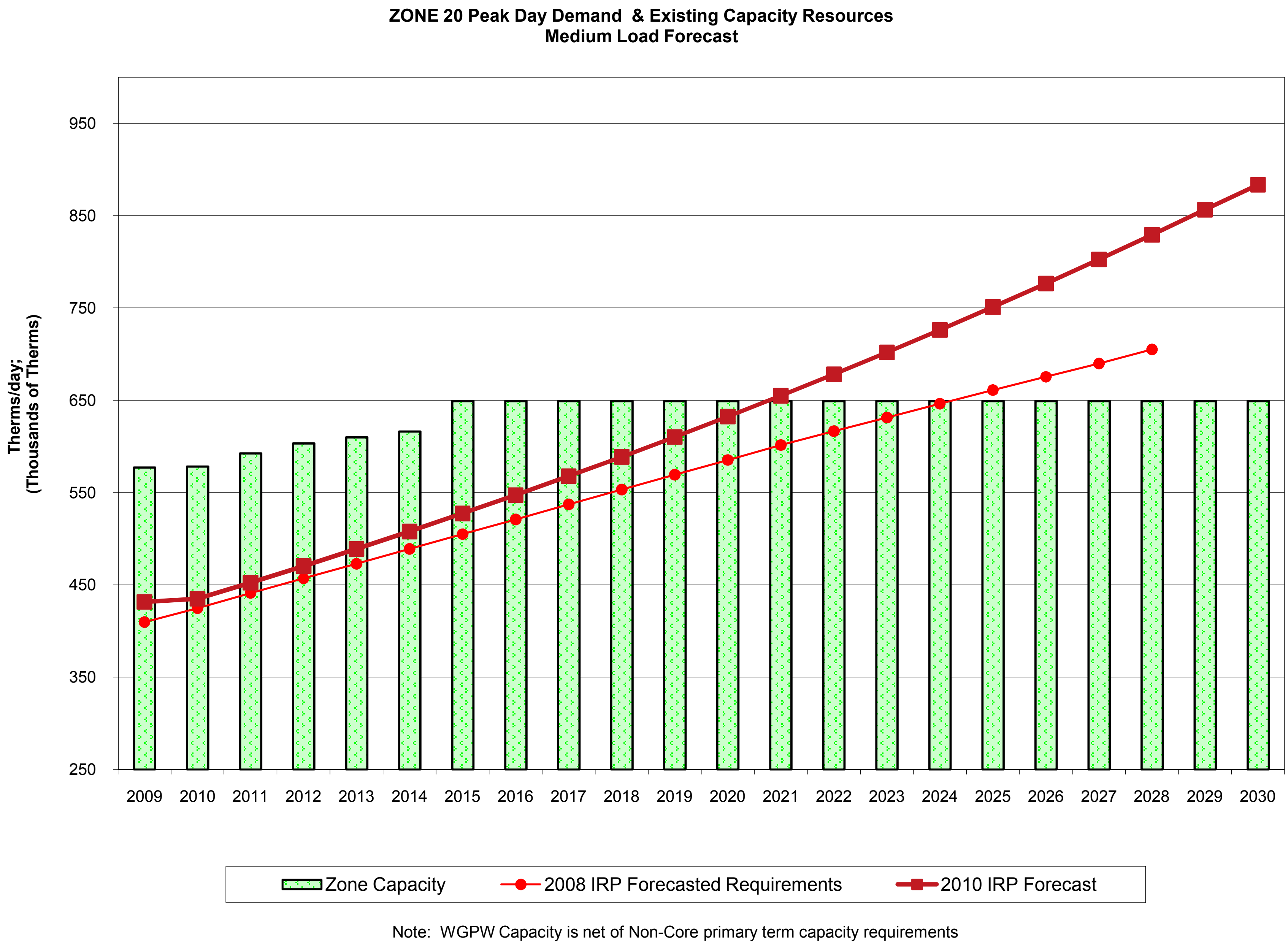
Note: WGPW Capacity is net of Non-Core primary term capacity requirements



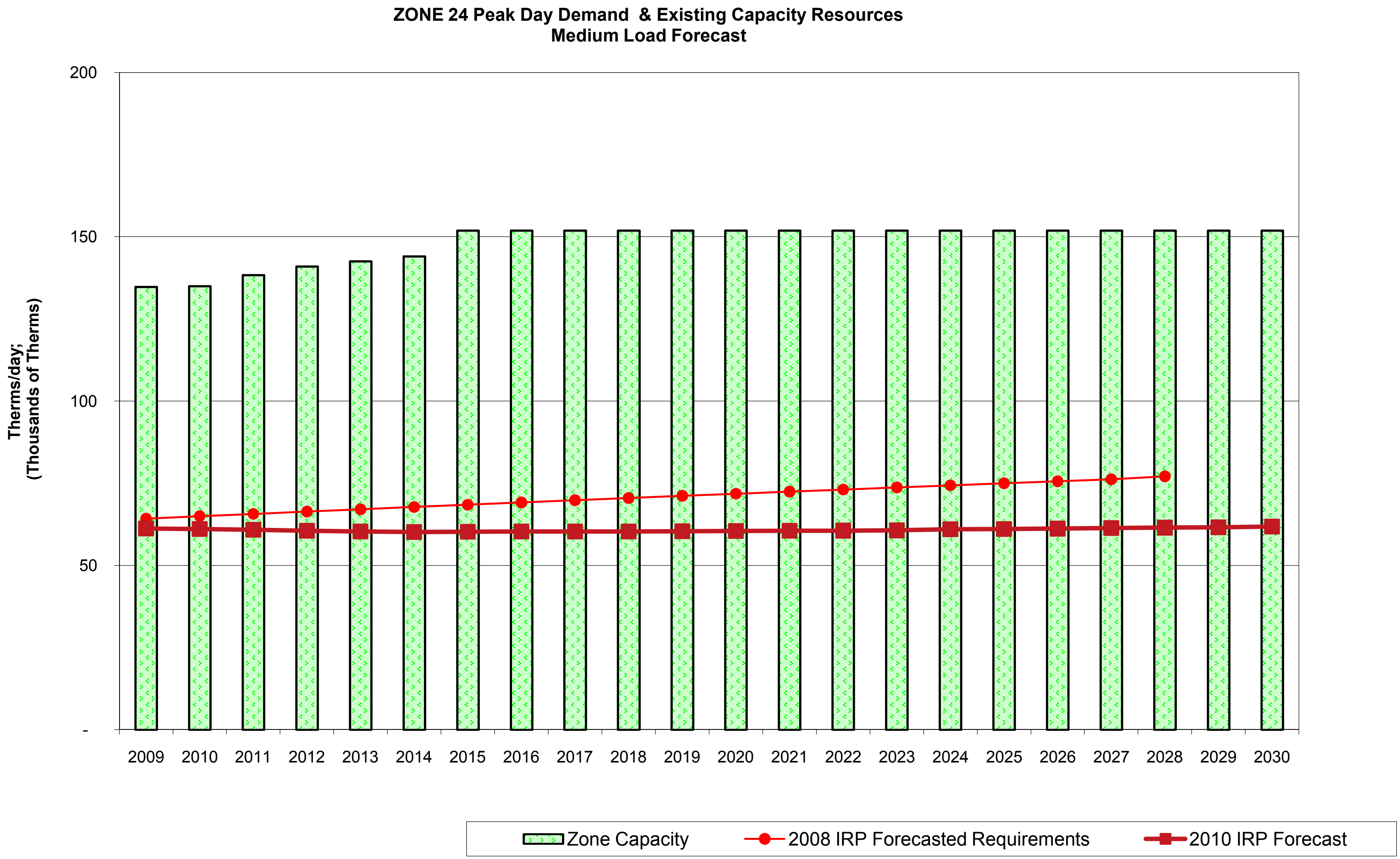
Note: WGPW Capacity is net of Non-Core primary term capacity requirements



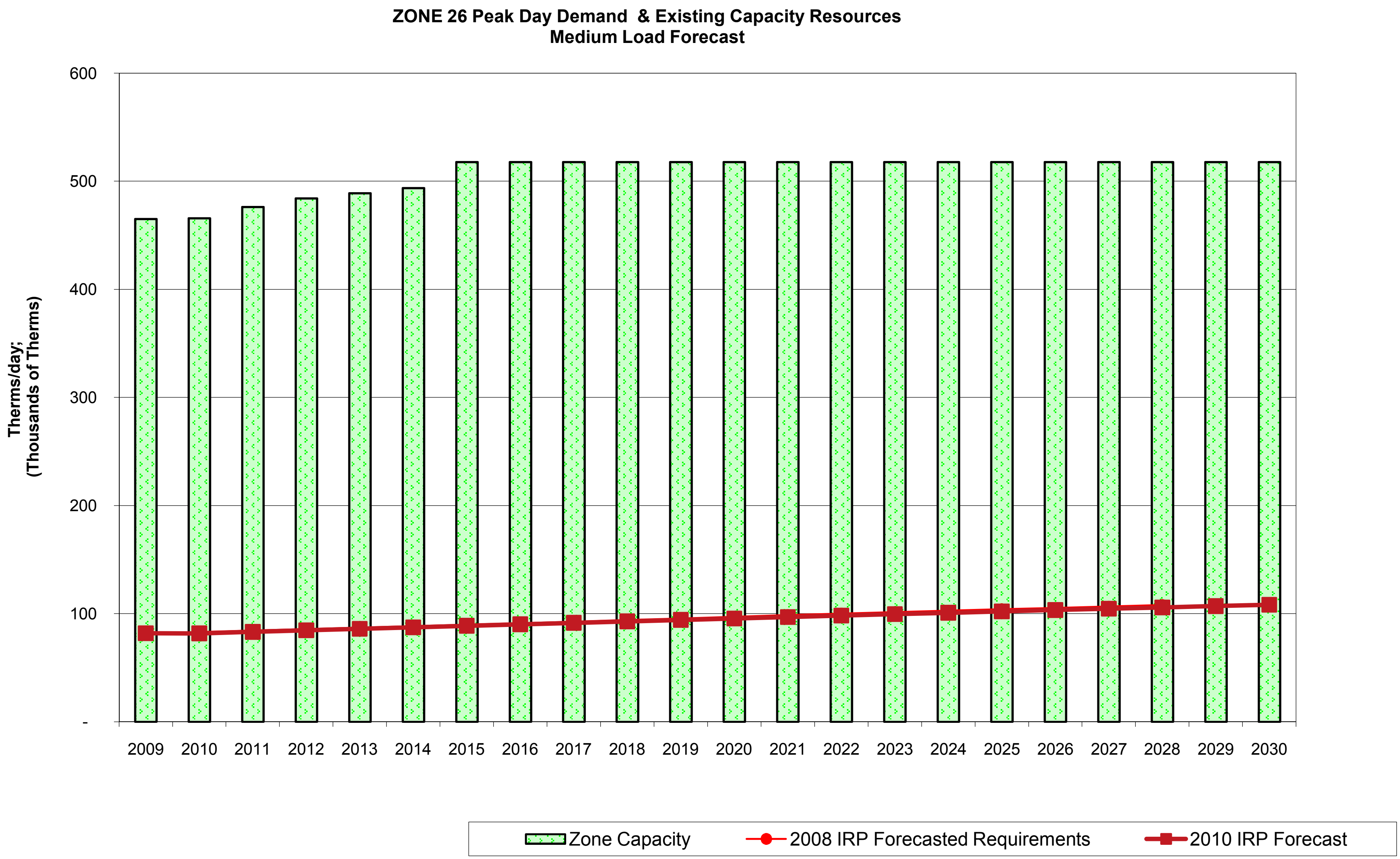
Note: WGPW Capacity is net of Non-Core primary term capacity requirements


ZONE 20 Peak Day Demand & Existing Capacity Resources
Medium Load Forecast
Therms/day;
(Thousands of Therms)
950
850
750
650
550
450
350
250
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Zone Capacity
2008 IRP Forecasted Requirements
2010 IRP Forecast
Note: WGPW Capacity is net of Non-Core primary term capacity requirements

20

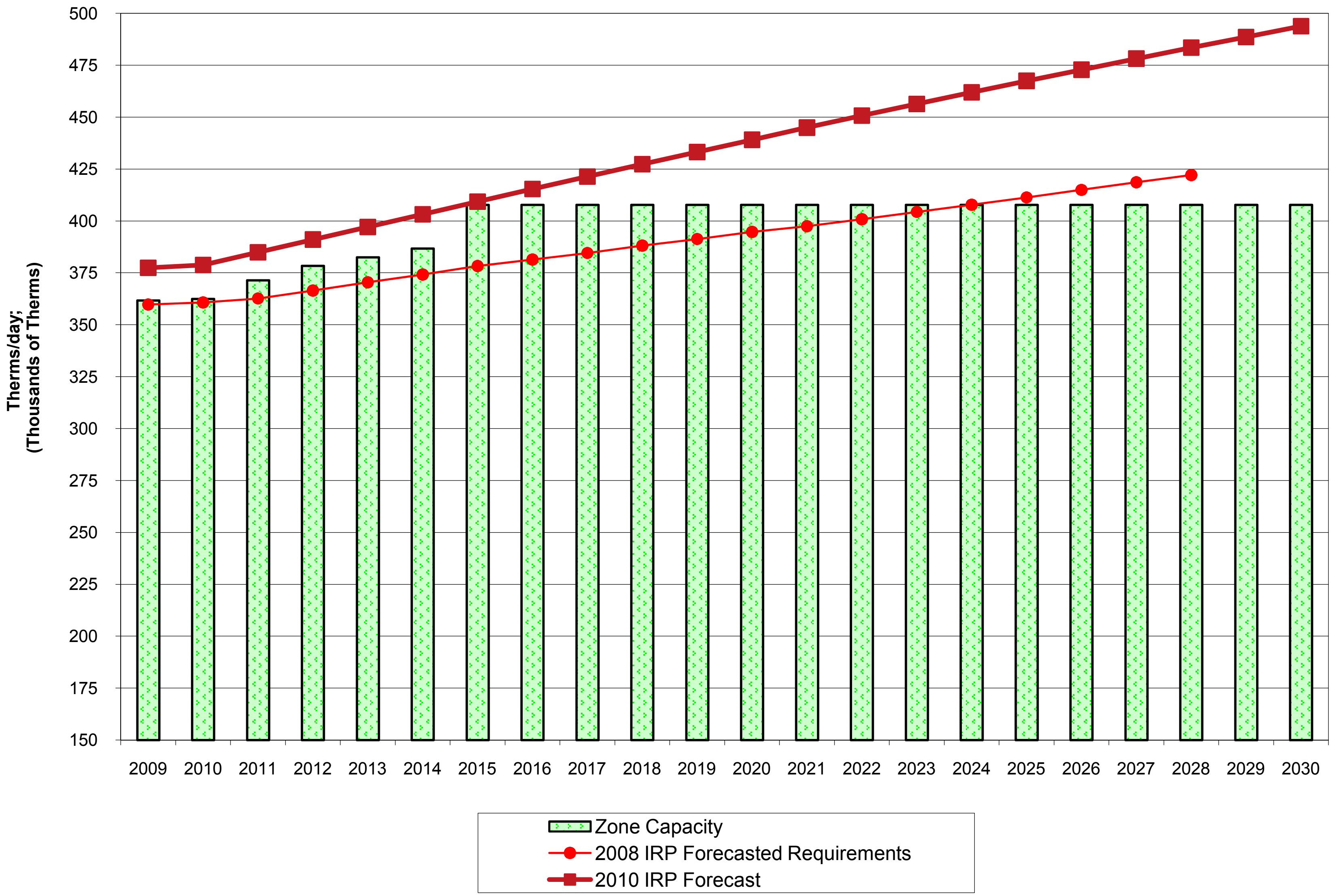


Note: WGPW Capacity is net of Non-Core primary term capacity requirements



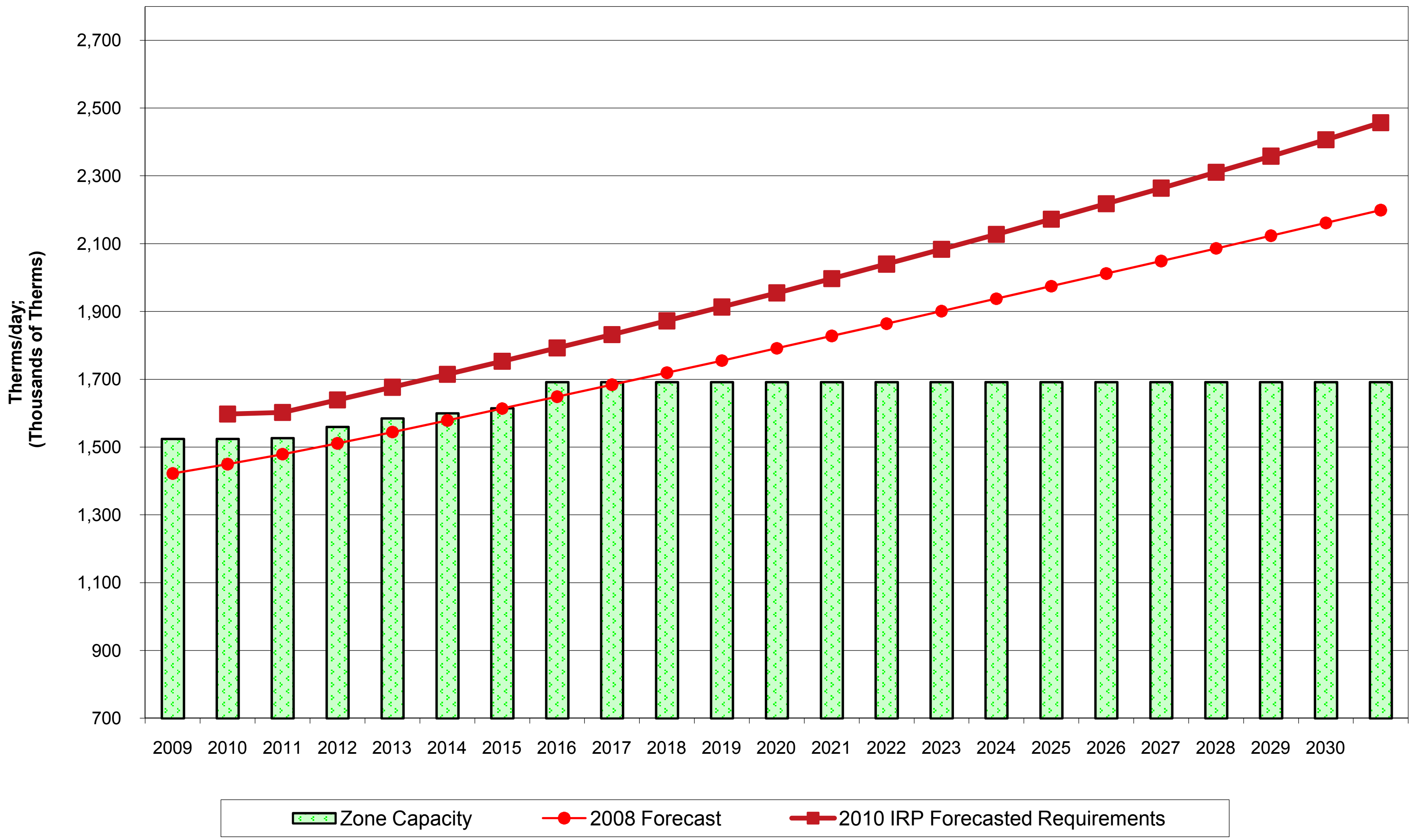
Note: WGPW Capacity is net of Non-Core primary term capacity requirements

ZONE ME Peak Day Demand & Existing Capacity Resources
Medium Load Forecast



Note: WGPW Capacity is net of Non-Core primary term capacity requirements

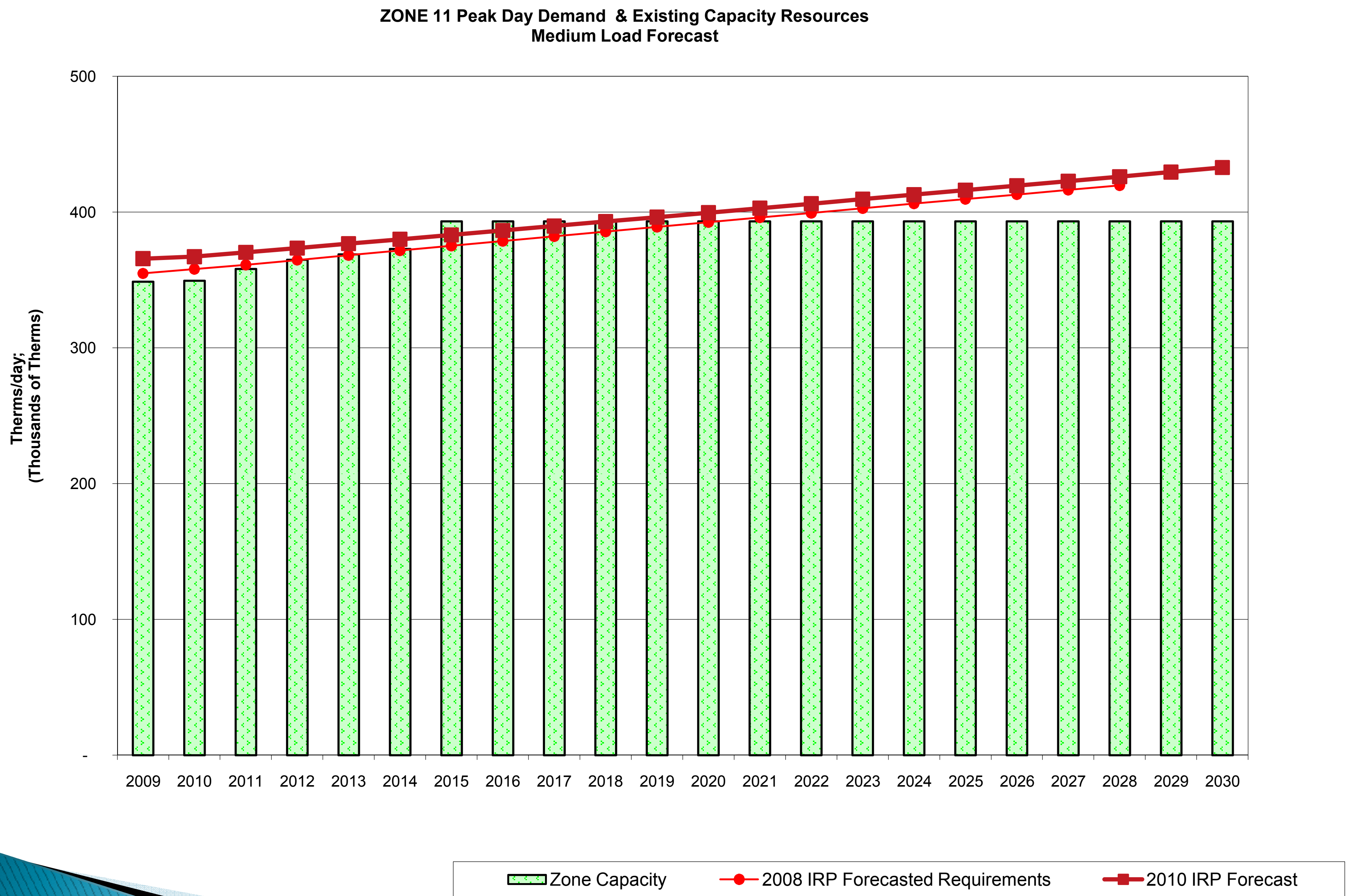
ZONE 30 Peak Day Demand & Existing Capacity Resources
Medium Load Forecast



Note: WGPW Capacity is net of Non-Core primary term capacity requirements

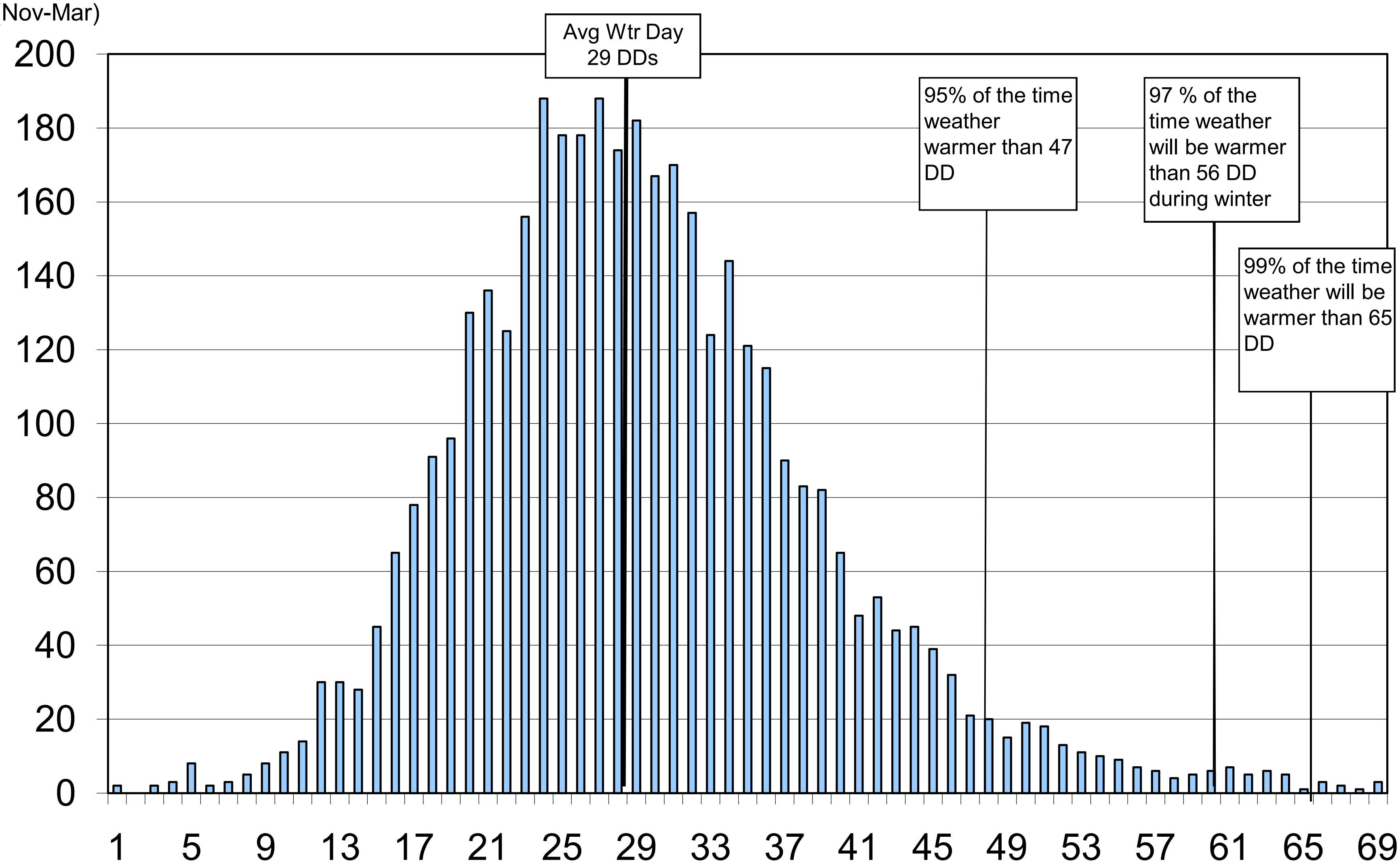
Peak Day & Capacity Shortfall Analysis

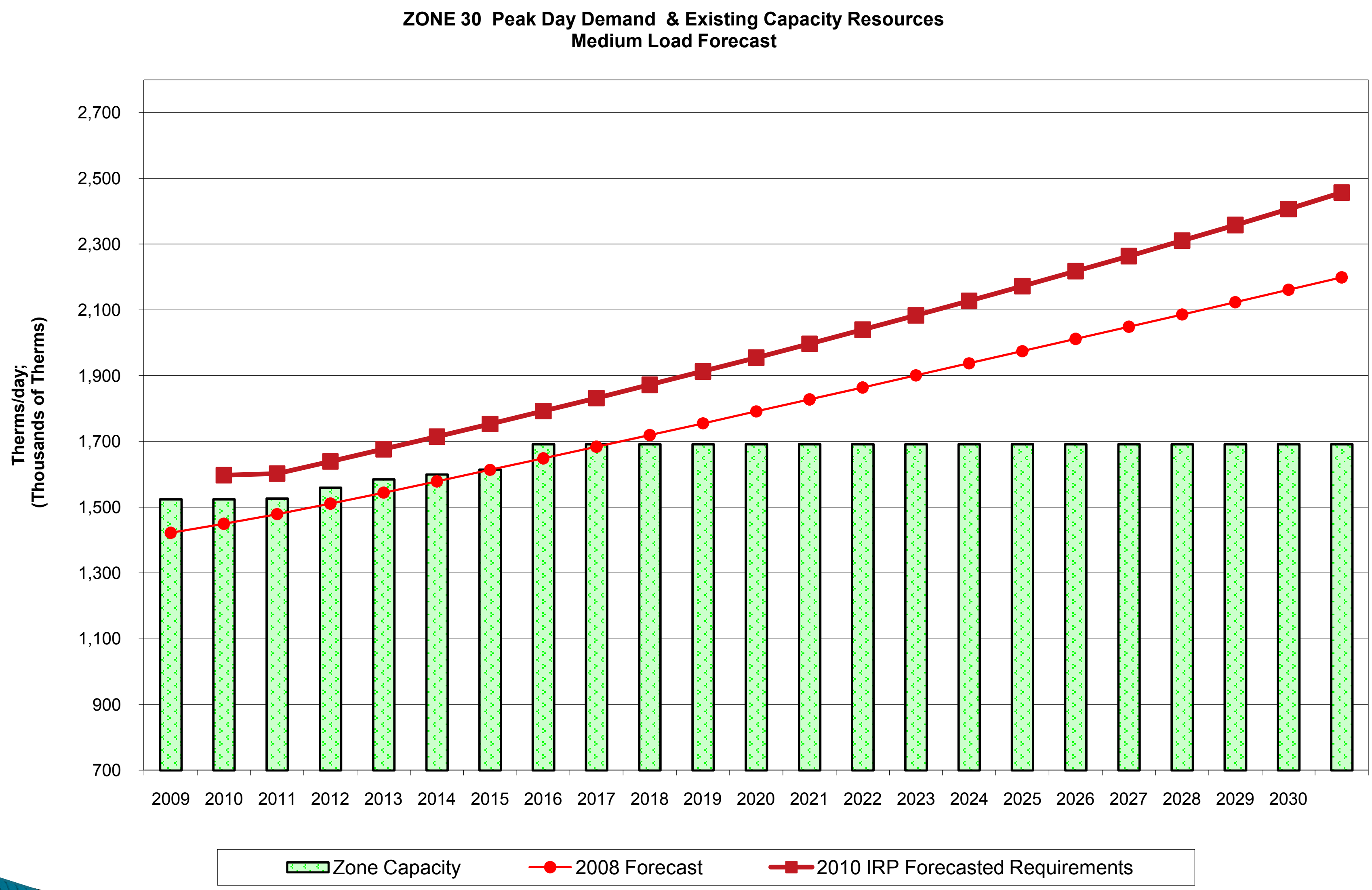
- Identify Capacity Shortfalls
  - Overall Pipeline Receipt Capabilities vs Peak Day Demand
  - Delivery Capabilities at the Gate (MDDO's)
  - Distribution System Needs
- Identify/Evaluate solutions
  - Determining magnitude of shortfall (degree day coverage)



Note: WGPW Capacity is net of Non-Core primary term capacity requirements

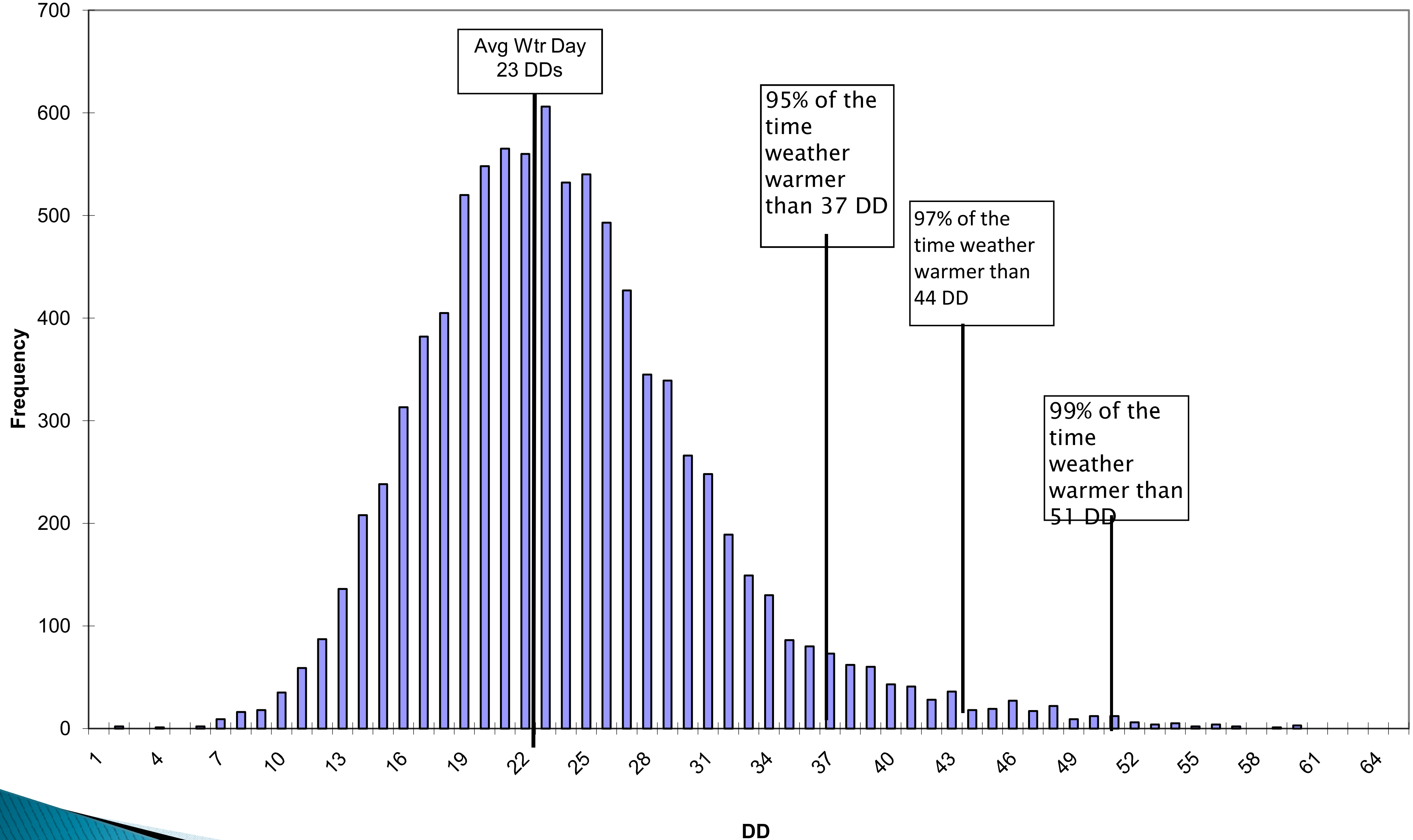
Zone 11-Winter Weather Frequency
(Nov-Mar)



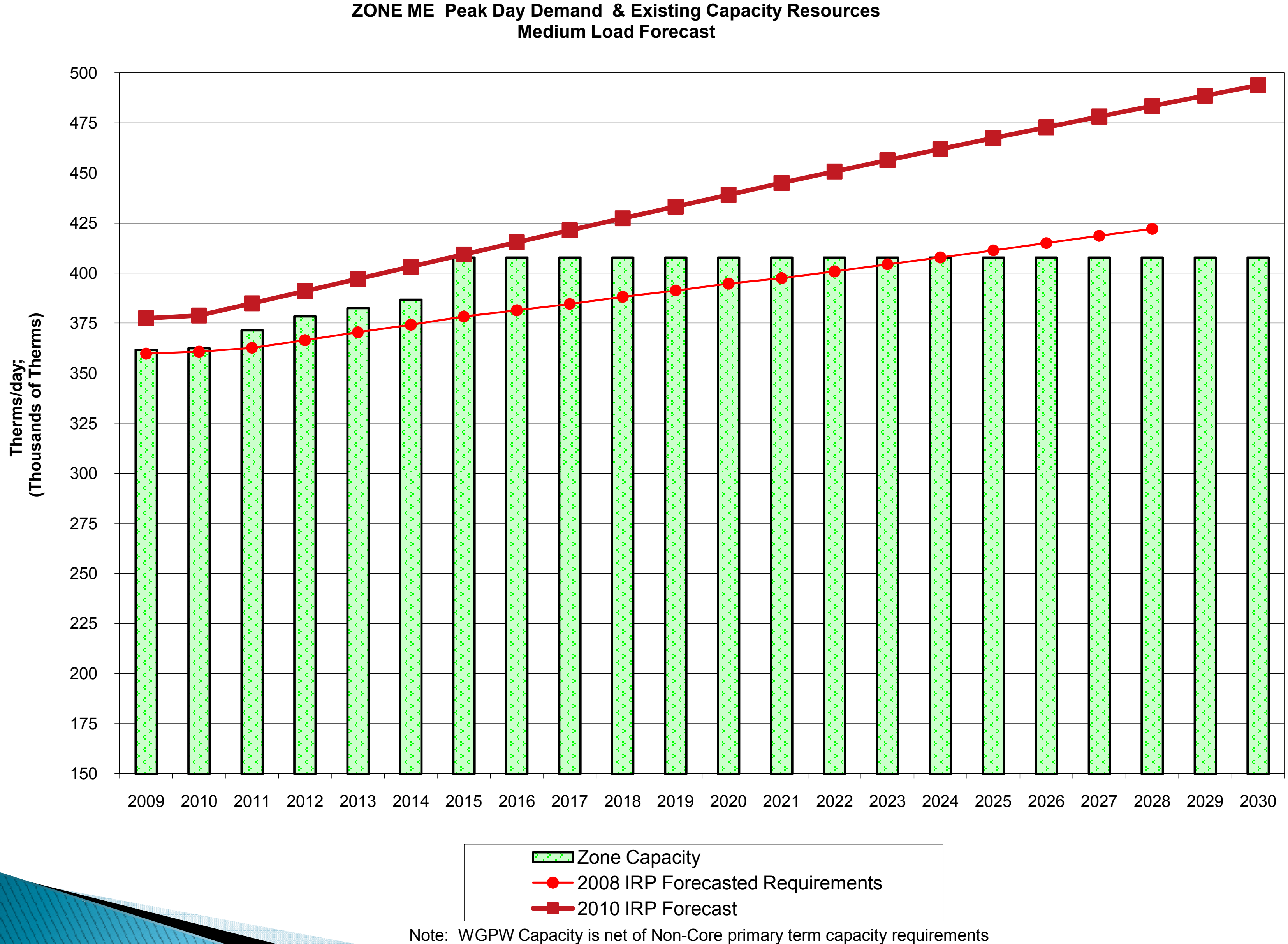


Note: WGPW Capacity is net of Non-Core primary term capacity requirements

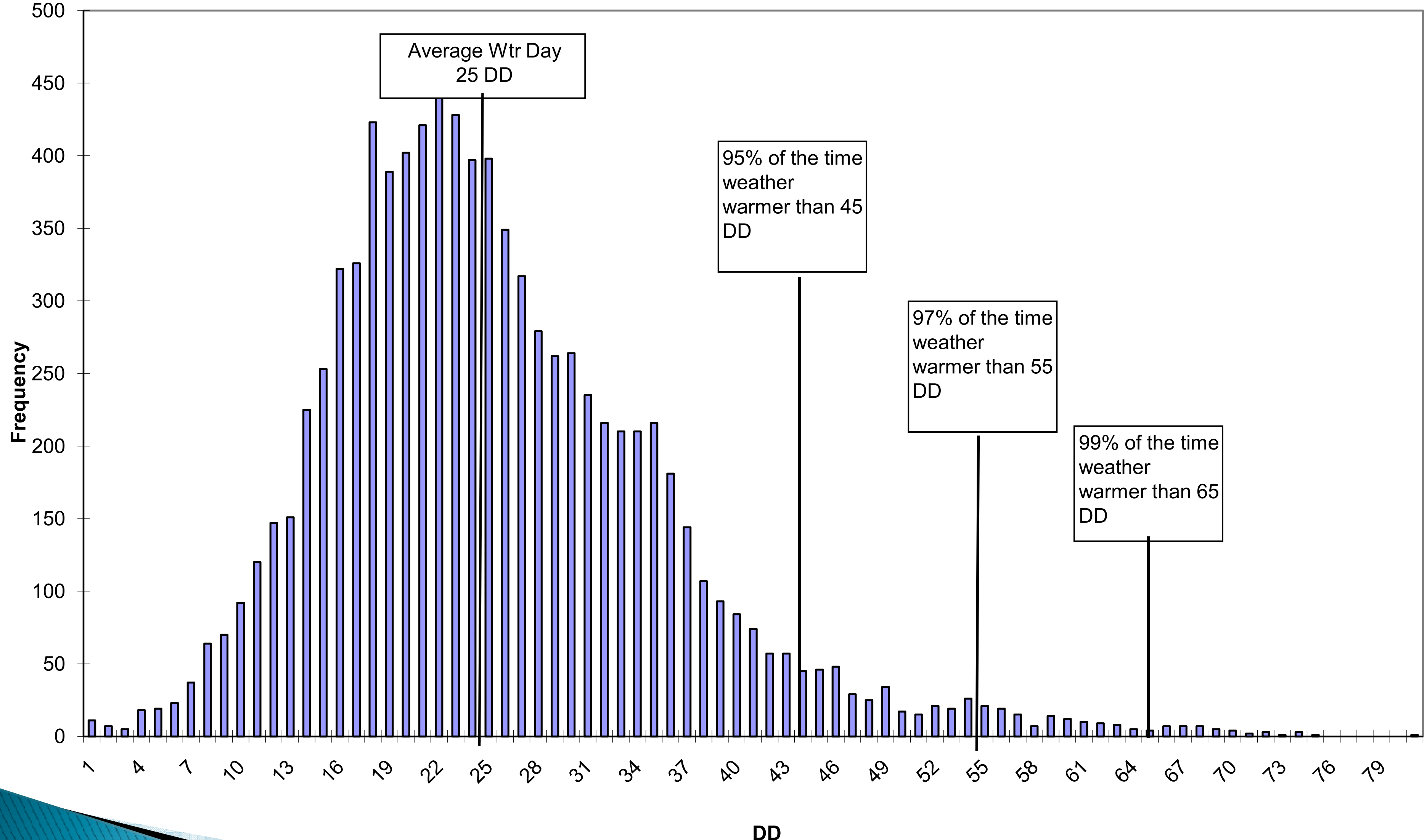
Zone 30-W Winter Weather Frequency (Nov-Mar)

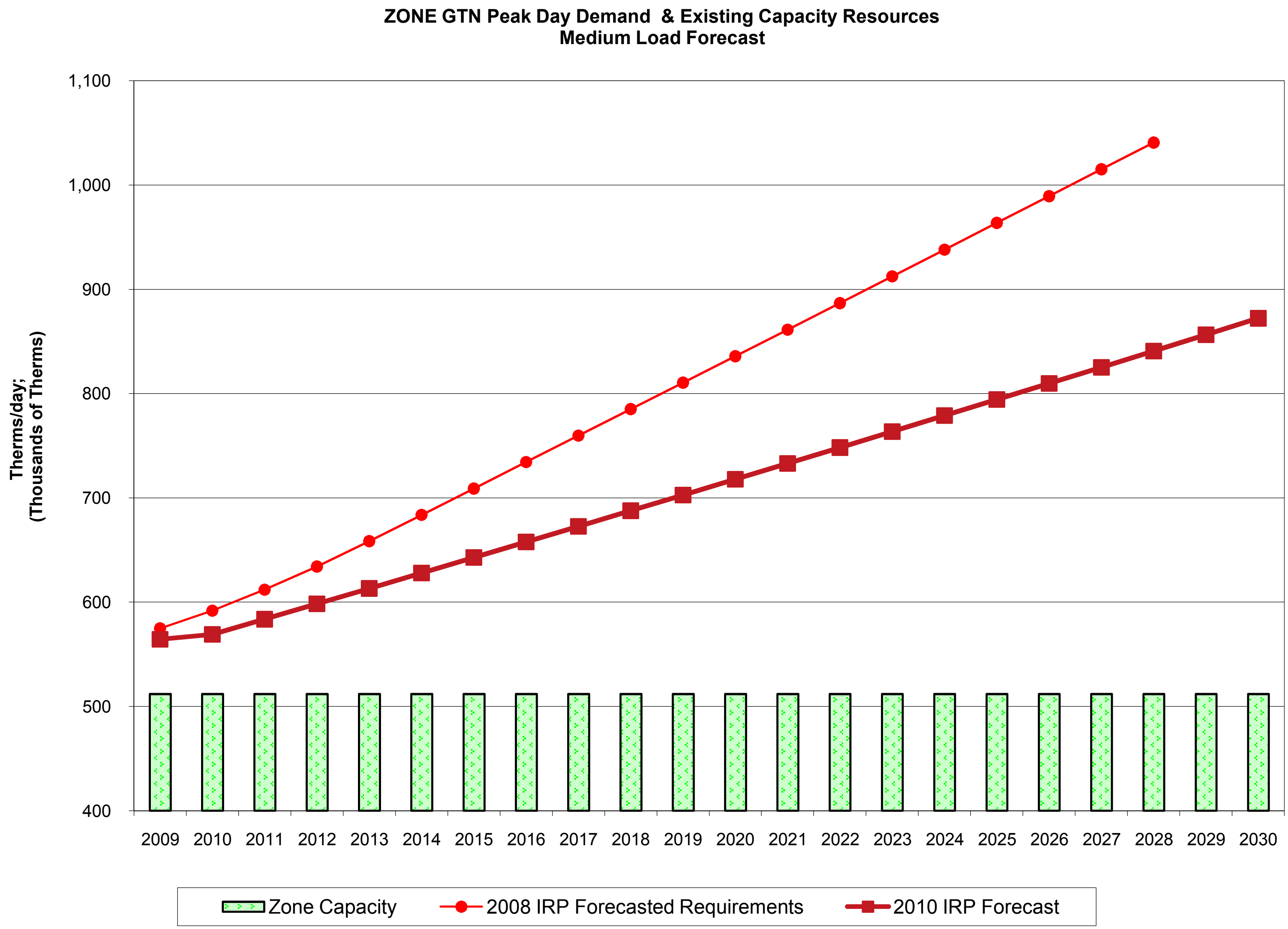


29


ZONE ME Peak Day Demand & Existing Capacity Resources
Medium Load Forecast
Therms/day;
(Thousands of Therms)
500
475
450
425
400
375
350
325
300
275
250
225
200
175
150
2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
Zone Capacity
2008 IRP Forecasted Requirements
2010 IRP Forecast
Note: WGPW Capacity is net of Non-Core primary term capacity requirements

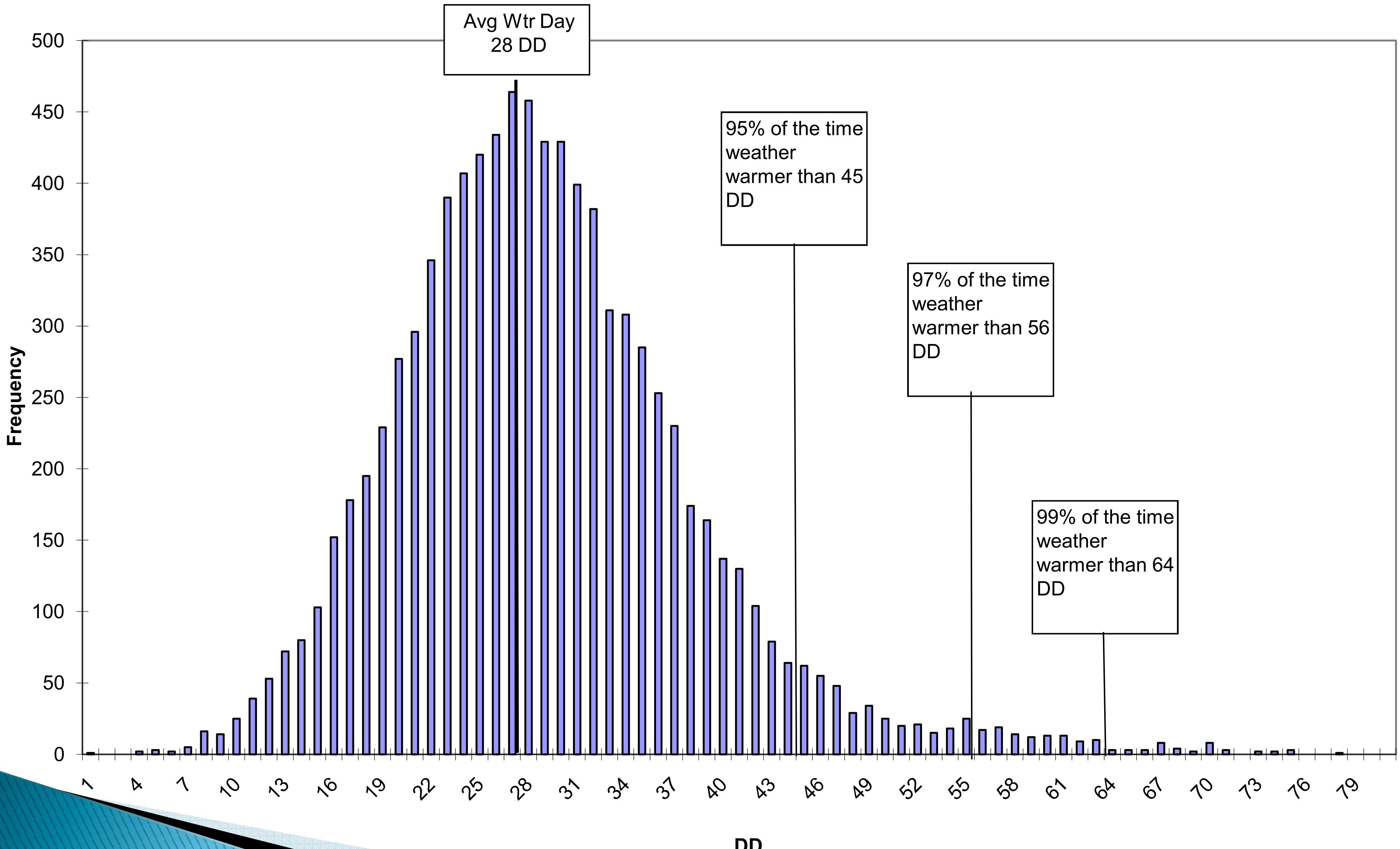
Zone ME Winter Weather Frequency (Nov-Mar)





Note: WGPW Capacity is net of Non-Core primary term capacity requirements

Zone GTN-Winter Weather Frequency
(Nov-Mar)



Integration Modeling: SENDOUT Data Elements

SUPPLY

Based on market intelligence we feel there is sufficient supply for the planning horizon

–Annual Supplies

–Traditional Seasonal Supplies (Nov-Mar)

–Off-Seasonal Supplies (Apr-Oct)

–Just-in-Time (Day Gas Purchases)

–Citygate Deliveries

–Storage Resources

–Peaking Supplies

–Unconventional Supply Resources

Price Forecast

- Used multiple sources for developing price forecast
  - Wood Mackenzie
  - NYMEX (which as of Jan08, provides real-time market through 2022)
  - NW Power Planning Council
  - EIA
  - Texas Comptroller Forecast

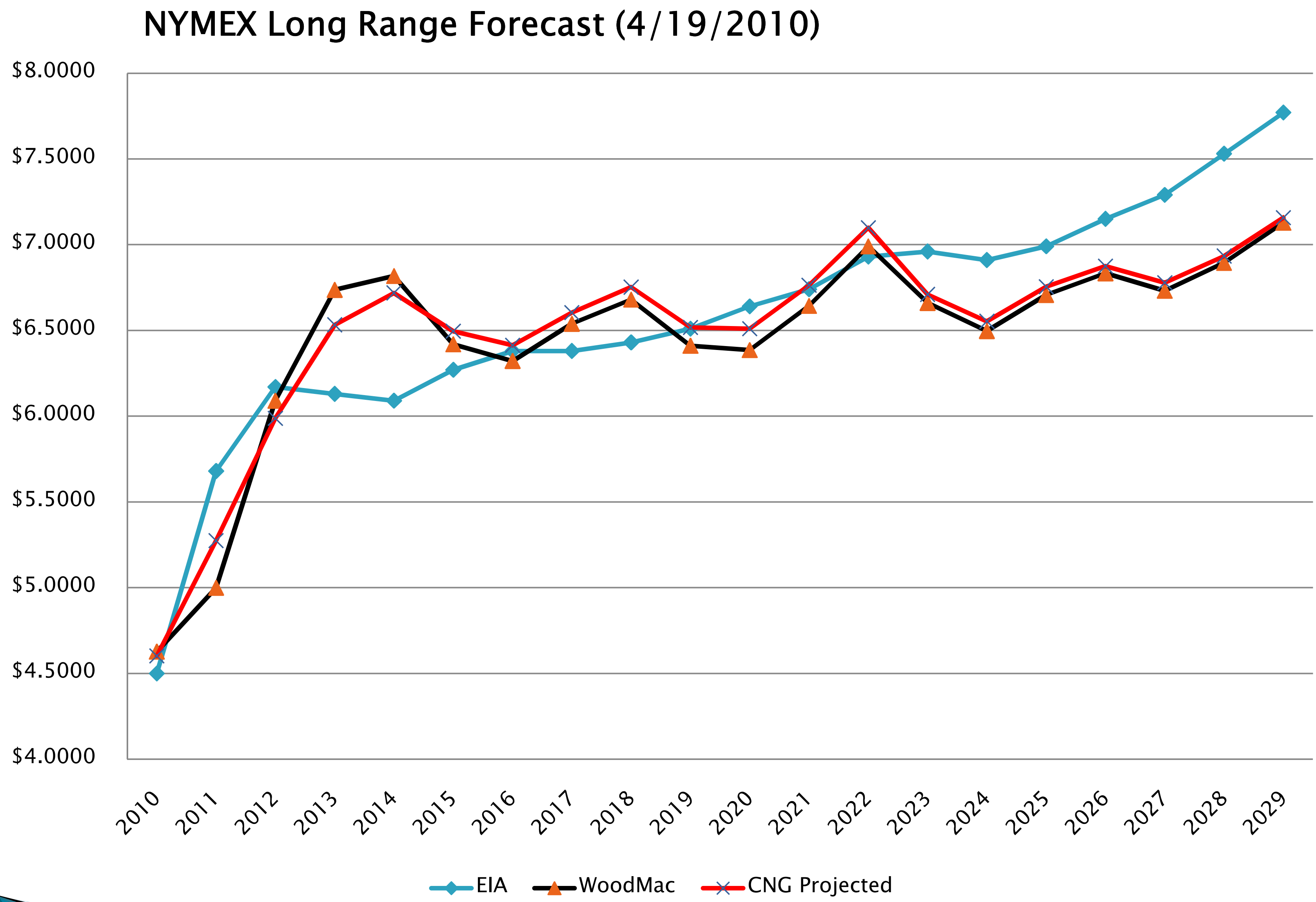
  - All sources did not have forecast prices for the entire 20 year period so known information was used to establish a pattern/trend which was applied to the sources that were missing relevant forecast data.

Price Forecast

- Prices developed as a weighted blend of the various price sources
- Among the factors considered are the publication date of the price source
- Historical accuracy
- Market conditions as they respond to industry intelligence

Current NYMEX/3rdParty/EIA

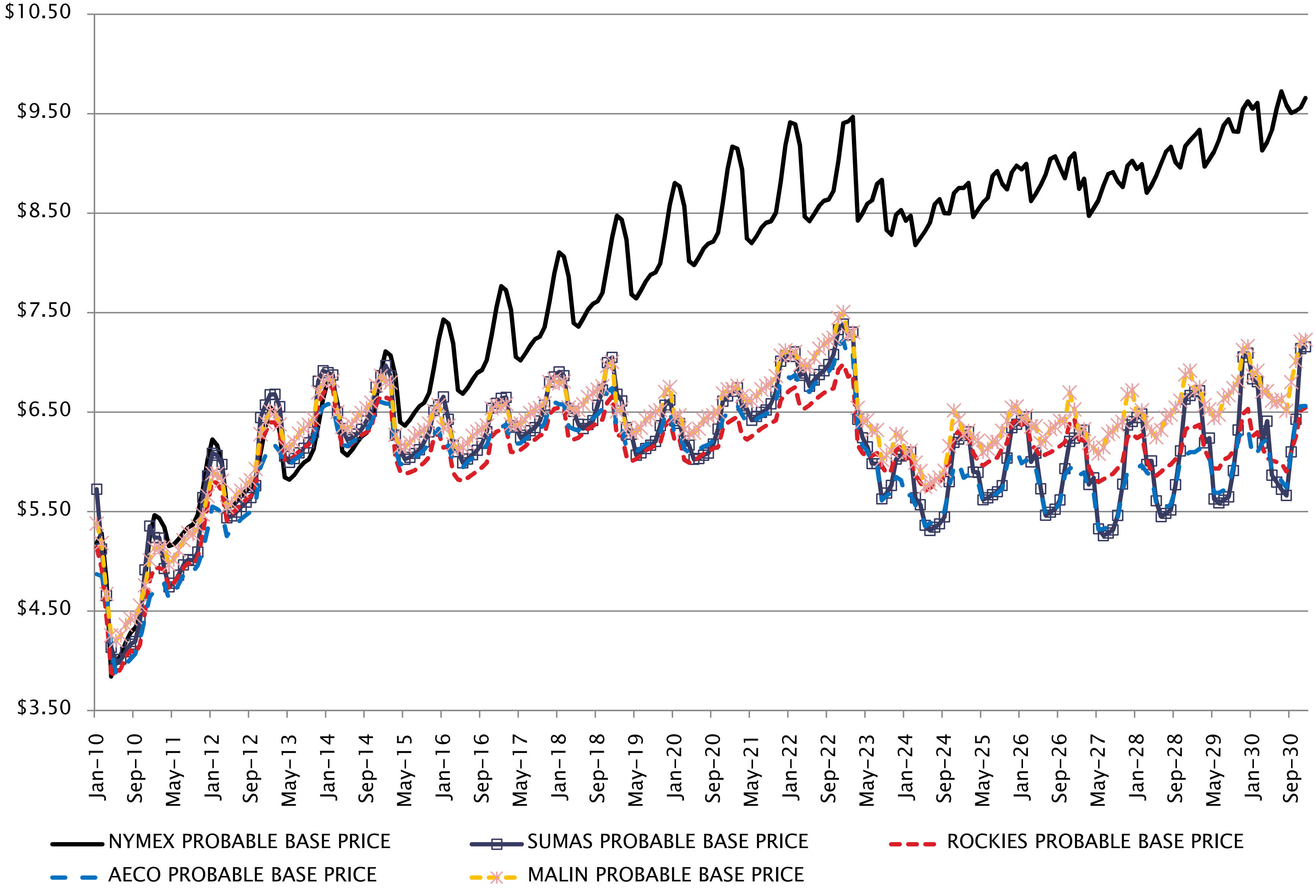
- Jan10–Oct12: 60/30/10
- Nov12–Oct13 40/40/20
- Nov13–Oct14 30/50/20
- Nov14–Oct15 20/60/20
- Nov15–Oct16 10/70/20
- Nov17–Dec22 5/75/20
- Jan23–Dec30 0/50/50

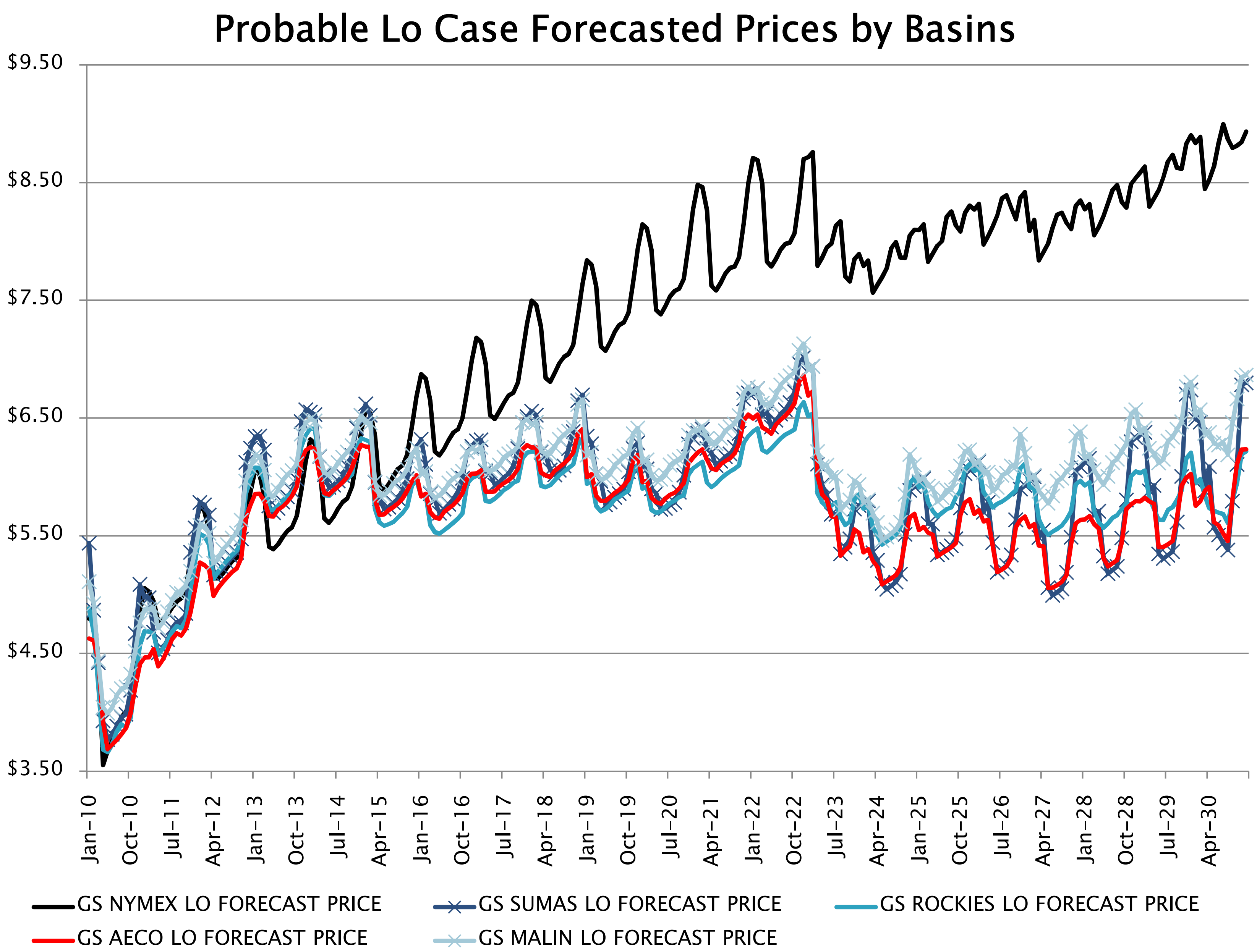


NYMEX Long Range Forecast (4/19/2010)
$8.0000
$7.5000
$7.0000
$6.5000
$6.0000
$5.5000
$5.0000
$4.5000
$4.0000
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
EIA
WoodMac
CNG Projected

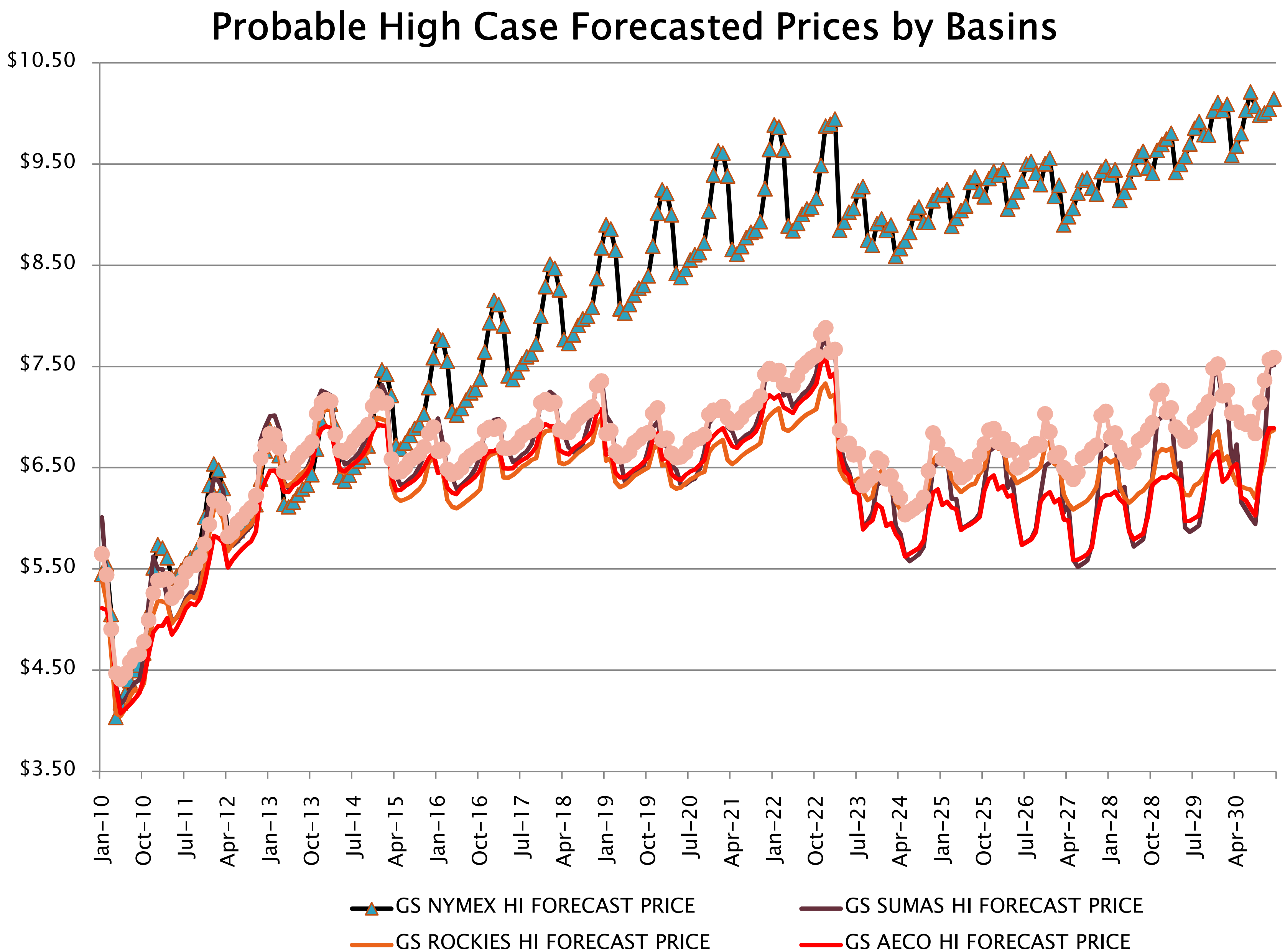
39

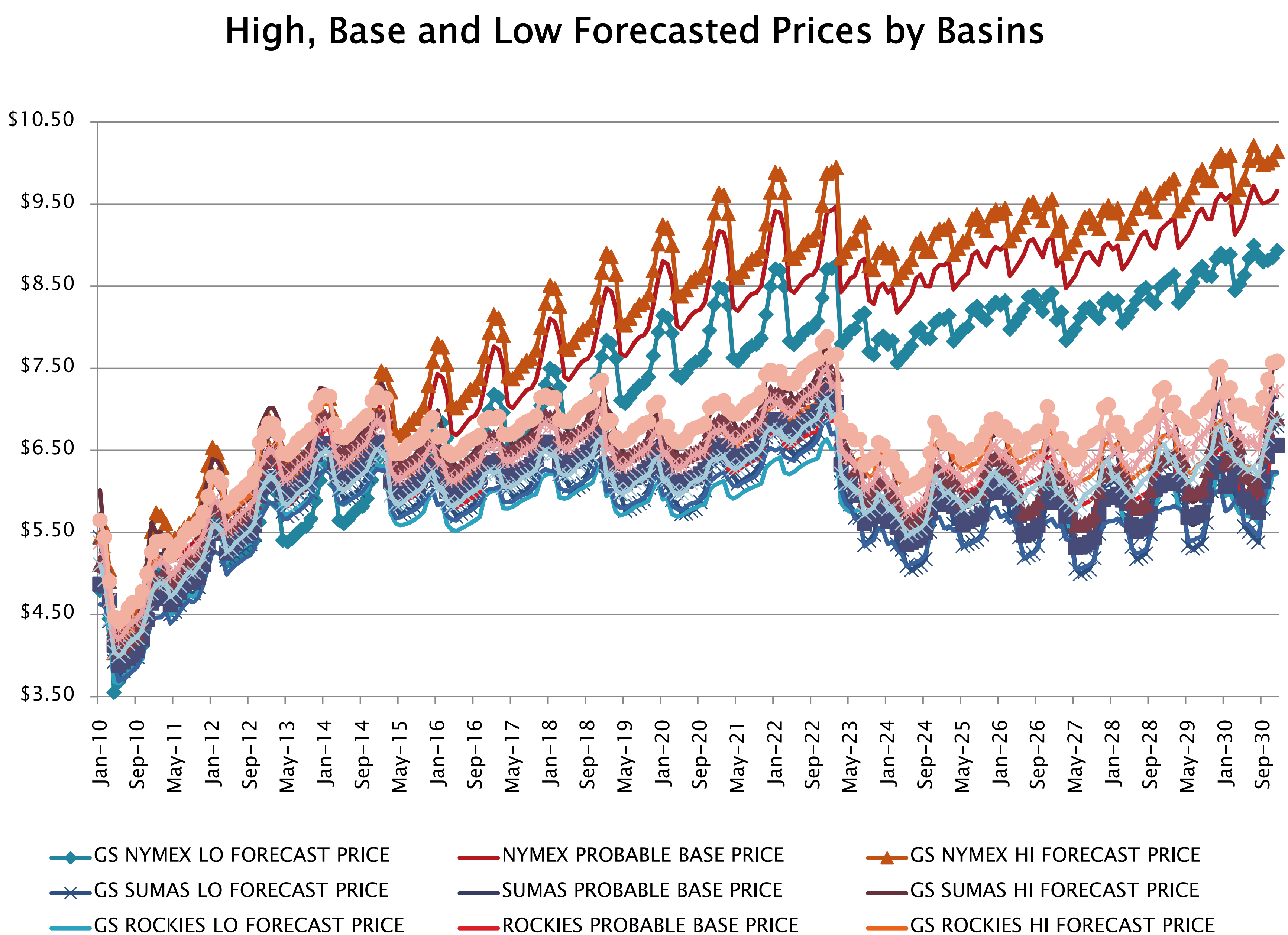
Probable Base Case Forecasted Prices by Basins





Probable Lo Case Forecasted Prices by Basins
$9.50
$8.50
$7.50
$6.50
$5.50
$4.50
$3.50
Jan-10
Oct-10
Jul-11
Apr-12
Jan-13
Oct-13
Jul-14
Apr-15
Jan-16
Oct-16
Jul-17
Apr-18
Jan-19
Oct-19
Jul-20
Apr-21
Jan-22
Oct-22
Jul-23
Apr-24
Jan-25
Oct-25
Jul-26
Apr-27
Jan-28
Oct-28
Jul-29
Apr-30
GS NYMEX LO FORECAST PRICE
GS SUMAS LO FORECAST PRICE
GS ROCKIES LO FORECAST PRICE
GS AECO LO FORECAST PRICE
GS MALIN LO FORECAST PRICE

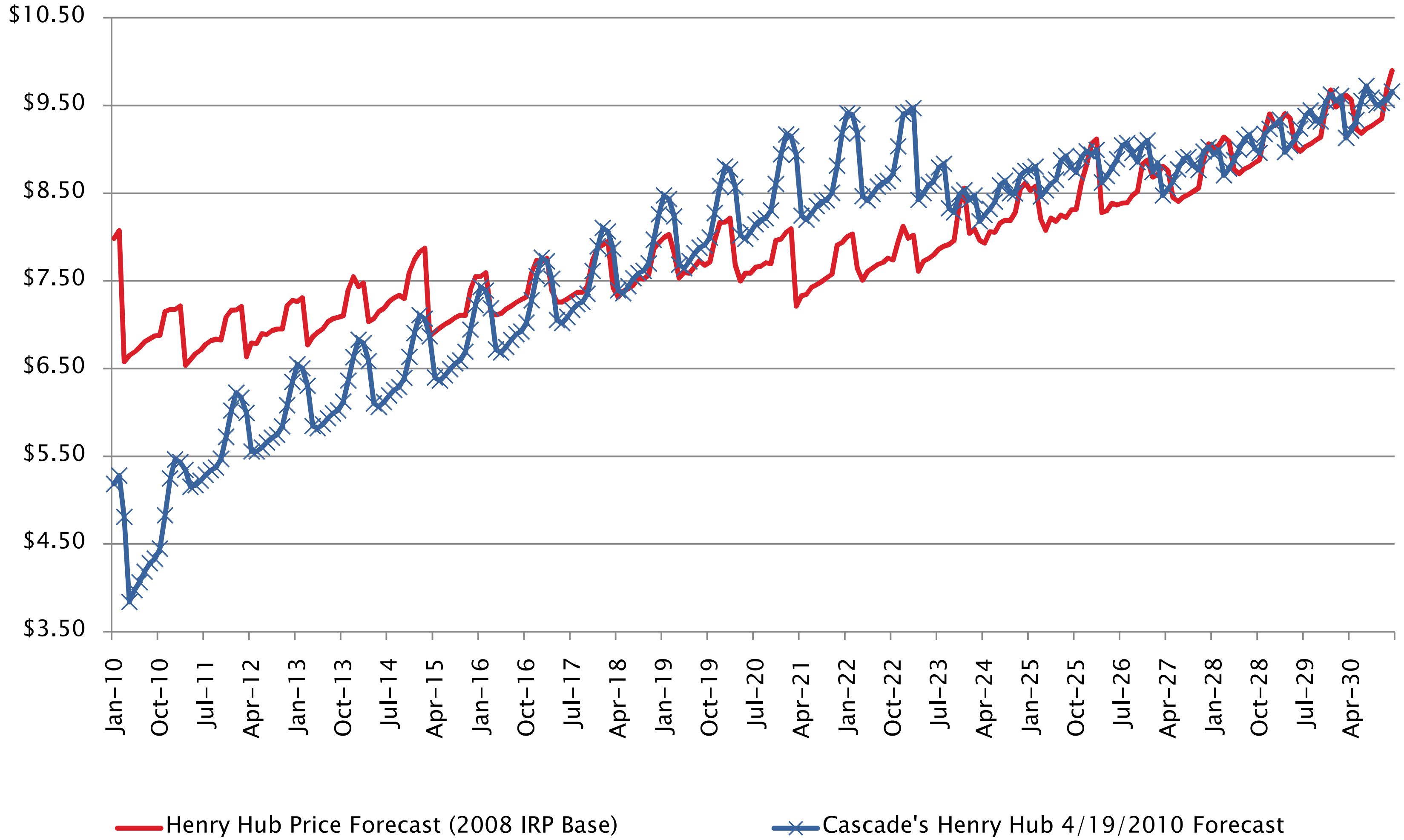

Probable High Case Forecasted Prices by Basins
$10.50
$9.50
$8.50
$7.50
$6.50
$5.50
$4.50
$3.50
Jan-10
Oct-10
Jul-11
Apr-12
Jan-13
Oct-13
Jul-14
Apr-15
Jan-16
Oct-16
Jul-17
Apr-18
Jan-19
Oct-19
Jul-20
Apr-21
Jan-22
Oct-22
Jul-23
Apr-24
Jan-25
Oct-25
Jul-26
Apr-27
Jan-28
Oct-28
Jul-29
Apr-30
GS NYMEX HI FORECAST PRICE
GS SUMAS HI FORECAST PRICE
GS ROCKIES HI FORECAST PRICE
GS AECO HI FORECAST PRICE



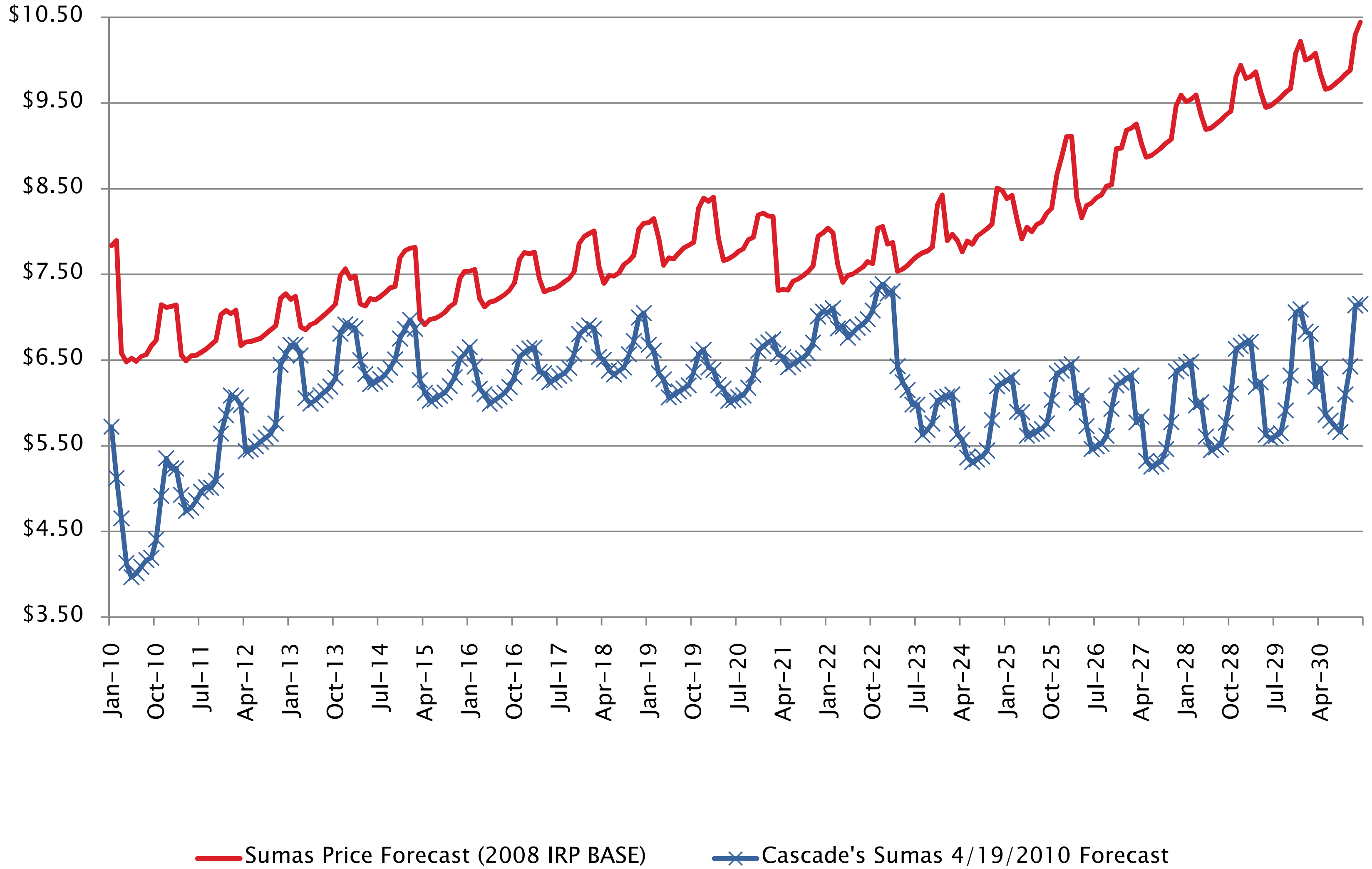
High, Base and Low Forecasted Prices by Basins
$10.50
$9.50
$8.50
$7.50
$6.50
$5.50
$4.50
$3.50
Jan-10
Sep-10
May-11
Jan-12
Sep-12
May-13
Jan-14
Sep-14
May-15
Jan-16
Sep-16
May-17
Jan-18
Sep-18
May-19
Jan-20
Sep-20
May-21
Jan-22
Sep-22
May-23
Jan-24
Sep-24
May-25
Jan-26
Sep-26
May-27
Jan-28
Sep-28
May-29
Jan-30
Sep-30
GS NYMEX LO FORECAST PRICE
NYMEX PROBABLE BASE PRICE
GS NYMEX HI FORECAST PRICE
GS SUMAS LO FORECAST PRICE
SUMAS PROBABLE BASE PRICE
GS SUMAS HI FORECAST PRICE
GS ROCKIES LO FORECAST PRICE
ROCKIES PROBABLE BASE PRICE
GS ROCKIES HI FORECAST PRICE

ONLY FAIR TO ASK—HOW DOES THE 2008 PRICE OUTLOOK LOOK COMPARED THE 2010?

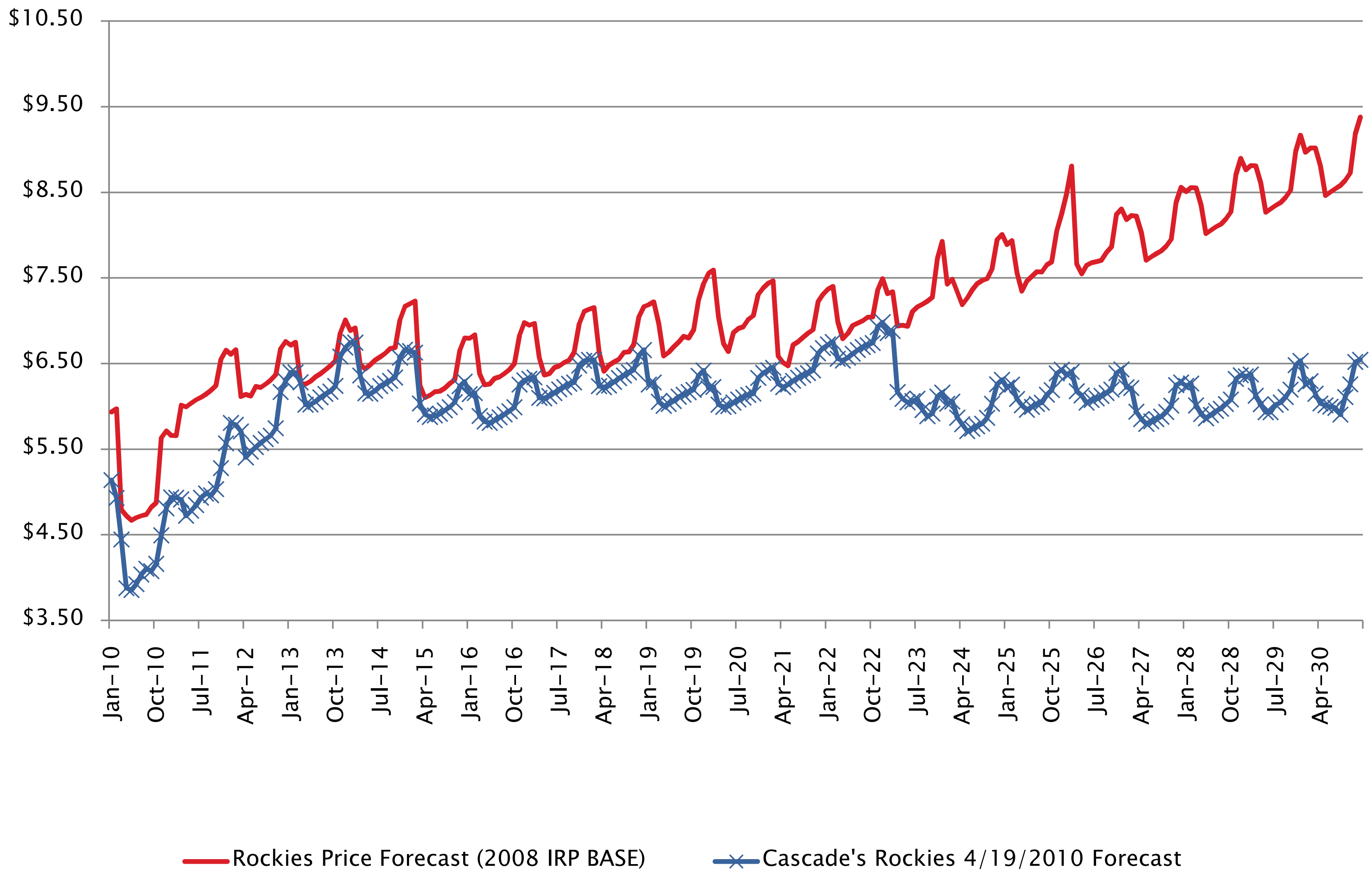
NYMEX HH Price Forecast Comparison 2008 vs 2010



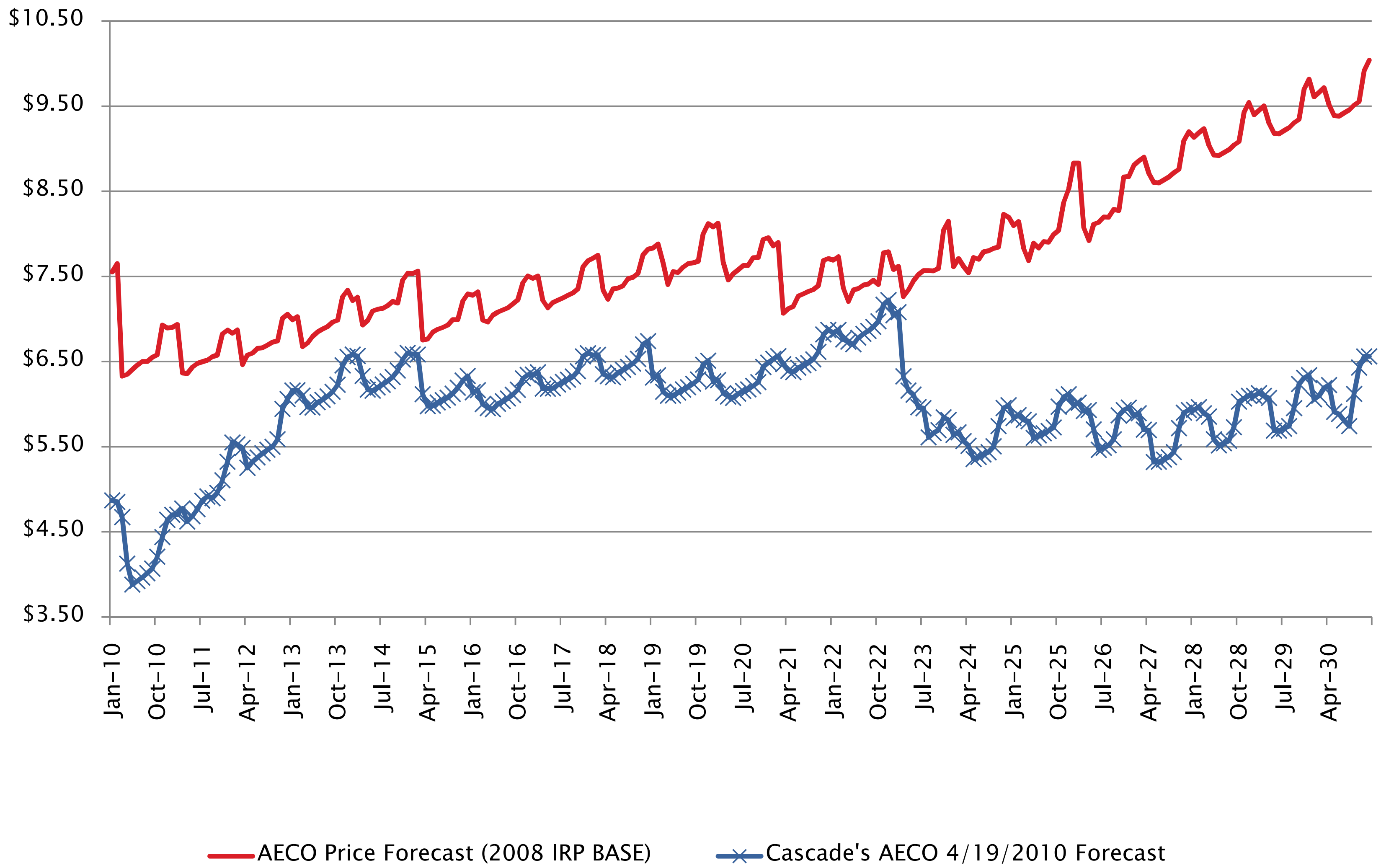
Sumas Price Forecast Comparison 2008 vs 2010



Rockies Price Forecast Comparison 2008 vs 2010



AECO Price Forecast Comparison 2008 vs 2010

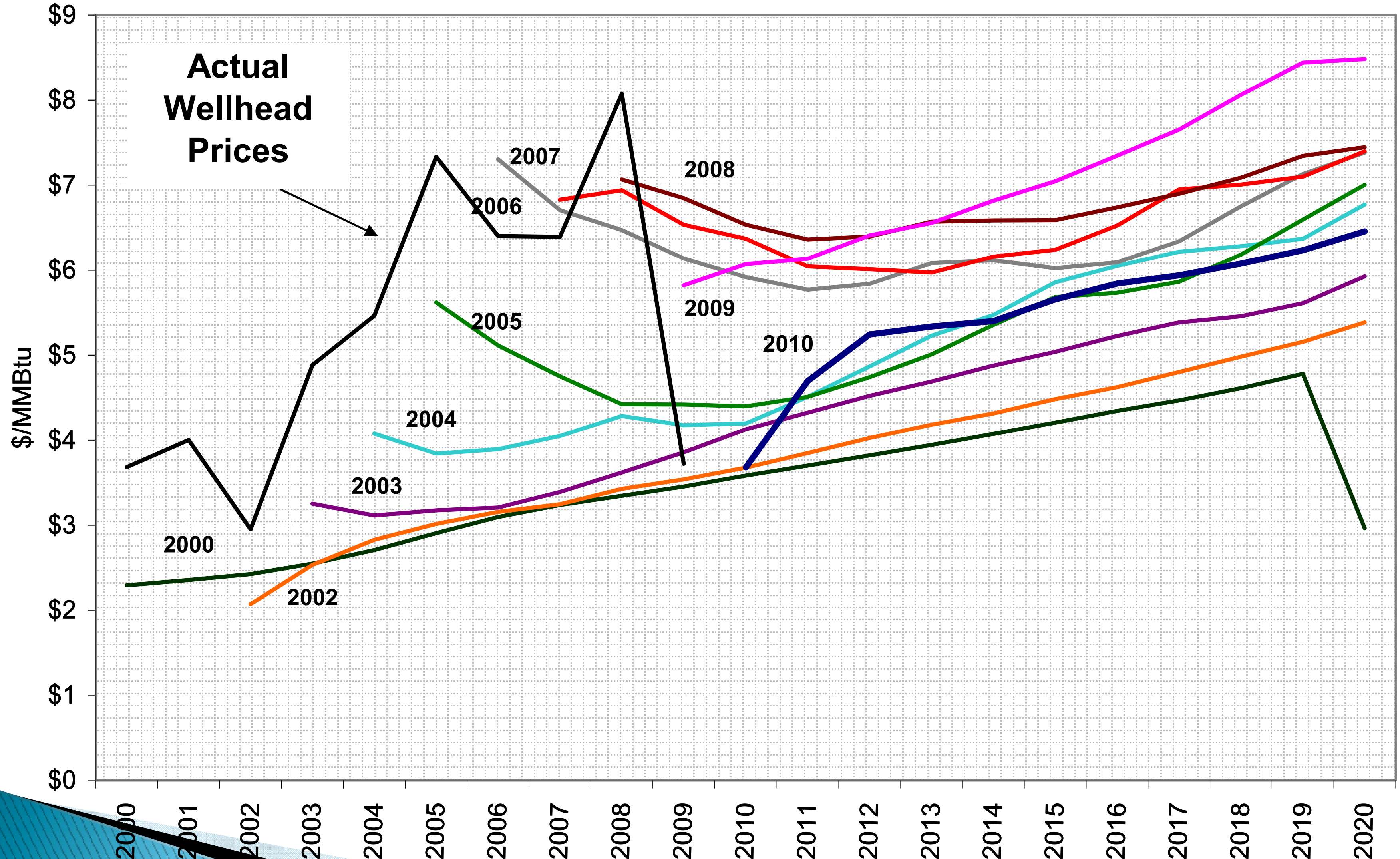


Observations 2008 vs 2010

- In the near range, noticeable difference in all the basins
- Overall, all the forecasts are lower; reflecting a lower "starting price" as a result of the recent economic havoc
- Interesting to note, the NYMEX forecast—other than in the near term—appears only slightly lower in the outer periods
  - Because HH is the standard trading point and basis differentials are much harder to predict?
- Tightness in 2015-2019 period, reflecting a return to economic stability in the 2010 forecast
- AECO and Sumas prices reflects the new economic situation but more importantly, the robust expectations for Canadian shale
- Rockies forecast differences reflect the abundance of shale as well as a belief price parity across the basins
- Question is—will this parity truly occur?

	ROCKIES PRICE COMPARED TO SUMAS		ROCKIES PRICE COMPARED TO AECO		ROCKIES PRICE COMPARED TO MALIN	
2010 Average	$	(0.24)	$	0.02	$	(0.30)
2011 Average	$	(0.12)	$	0.13	$	(0.24)
2012 Average	$	(0.11)	$	0.19	$	(0.13)
2013 Average	$	(0.11)	$	0.10	$	(0.14)
2014 Average	$	(0.13)	$	0.03	$	(0.18)
2015 Average	$	(0.22)	$	(0.07)	$	(0.27)
2016 Average	$	(0.27)	$	(0.11)	$	(0.32)
2017 Average	$	(0.22)	$	(0.07)	$	(0.28)
2018 Average	$	(0.23)	$	(0.08)	$	(0.31)
2019 Average	$	(0.17)	$	(0.08)	$	(0.30)
2020 Average	$	(0.12)	$	(0.08)	$	(0.31)
2021 Average	$	(0.26)	$	(0.15)	$	(0.39)
2022 Average	$	(0.30)	$	(0.18)	$	(0.45)
2023 Average	$	(0.03)	$	0.08	$	(0.26)
2024 Average	$	0.23	$	0.34	$	(0.09)
2025 Average	$	0.19	$	0.33	$	(0.15)
2026 Average	$	0.29	$	0.43	$	(0.18)
2027 Average	$	0.22	$	0.38	$	(0.32)
2028 Average	$	0.06	$	0.26	$	(0.43)
2029 Average	$	(0.05)	$	0.17	$	(0.54)
2030 Average	$	(0.17)	$	0.04	$	(0.64)
Grand Average	***$***	***(0.07)***	***$***	***0.08***	***$***	***(0.30)***

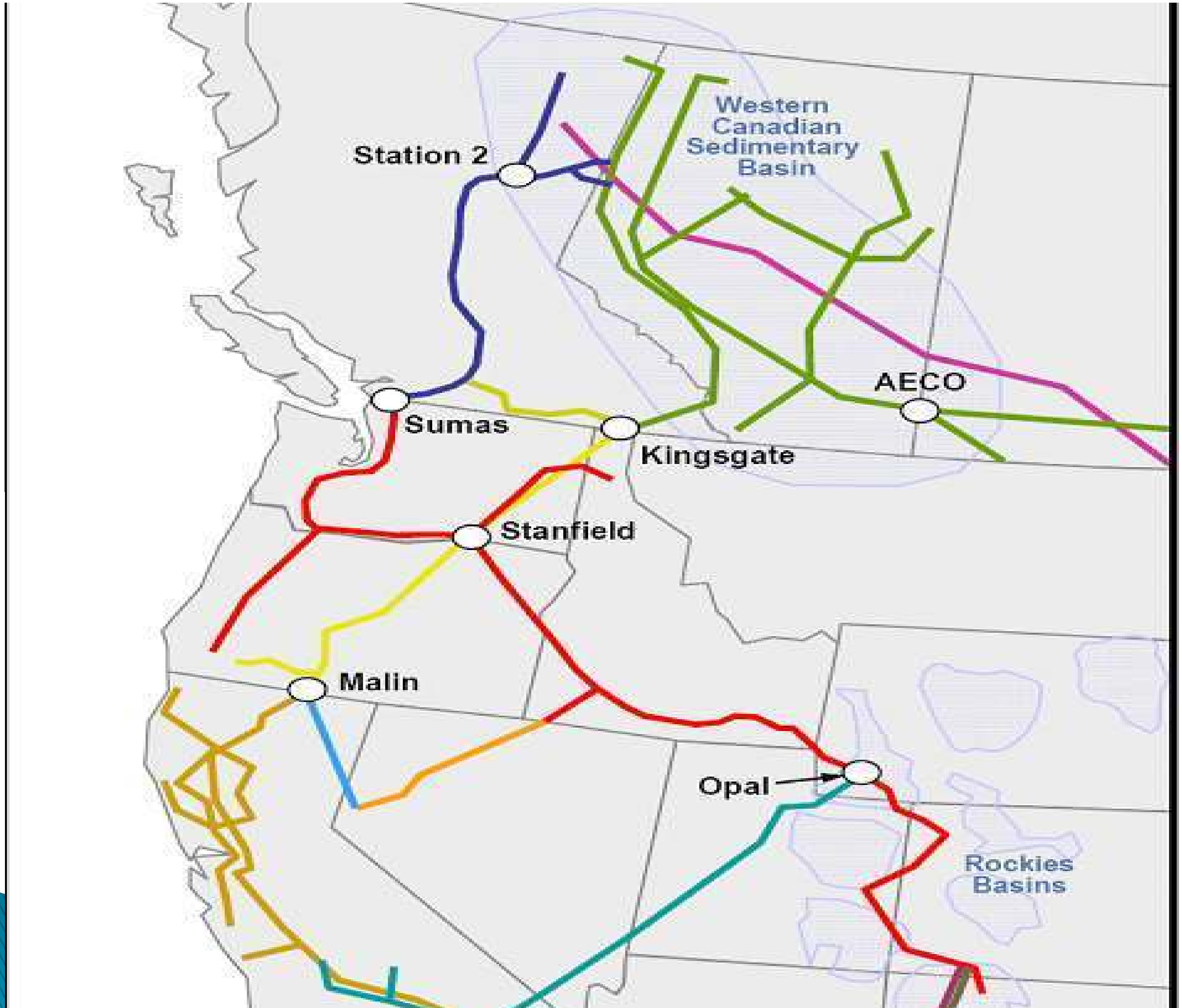
Historical Price Forecasts

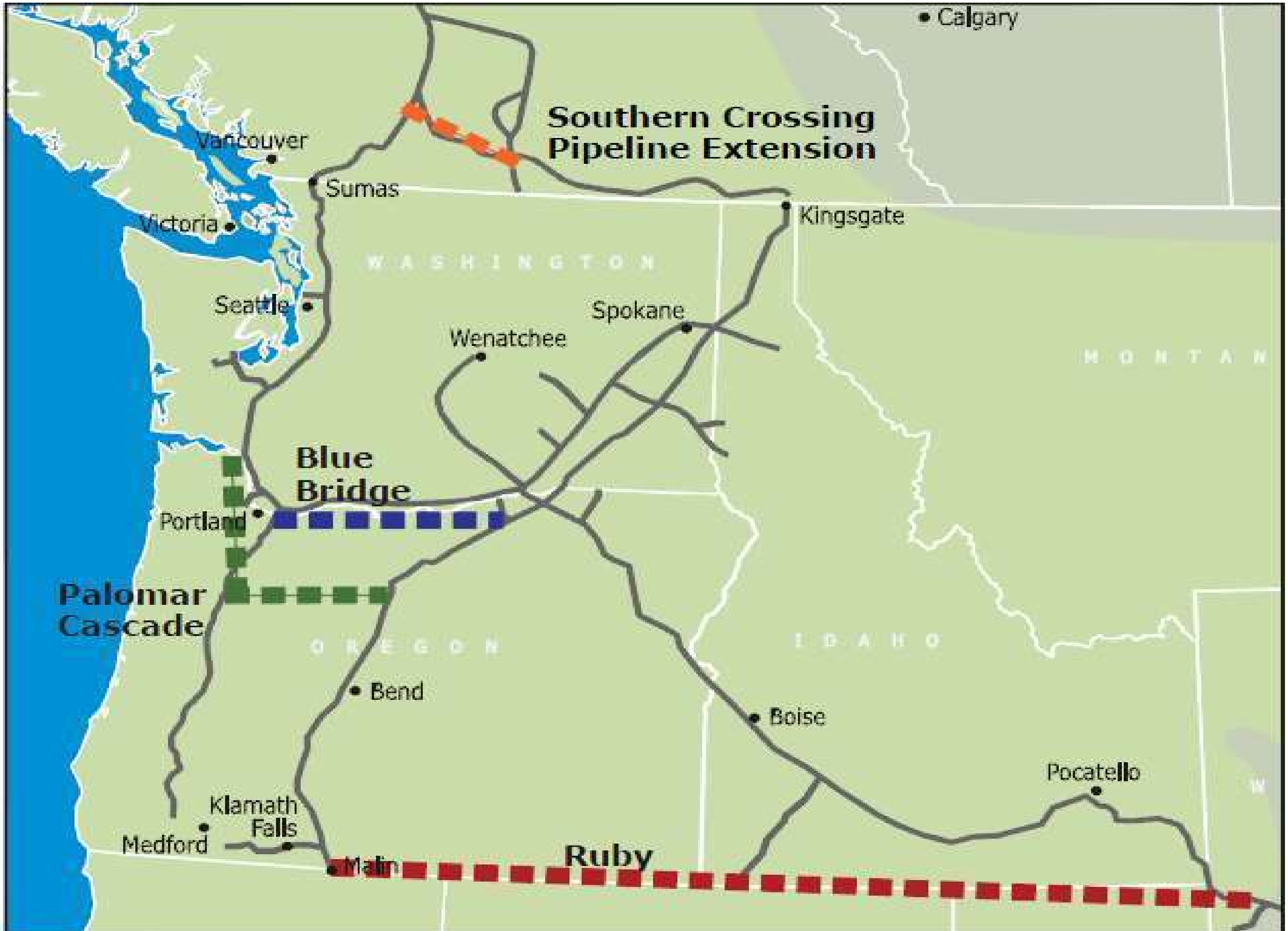


Source: EIA-Annual Energy Outlooks

SUPPLY SIDE RESOURCE MODELING

(PLEASE SEE HANDOUT)


Western
Canadian
Sedimentary
Basin
Station 2
AECO
Sumas
Kingsgate
Stanfield
Malin
Opal
Rockies
Basins


Calgary
Southern Crossing
Pipeline Extension
Vancouver
Sumas
Kingsgate
Victoria
WASHINGTON
Seattle
Spokane
Wenatchee
MONTANA
Blue
Bridge
Portland
Palomar
Cascade
OREGON
IDAHO
Bend
Boise
Pocatello
Klamath
Falls
Medford
Malin
Ruby

Kitimat LNG
Kitimat, B.C.
Pacific Trail Pipeline
BRITISH
COLUMBIA
Spectra Energy Western
Canadian Operations
Terasen Southern Crossing
TransCanada's GTN System
Williams Northwest Pipeline
Vancouver
Sumas
Victoria
WASHINGTON
Seattle
Northern Star
Bradwood, OR
Wenatchee
Spokane
Oregon LNG
Warrenton, OR
Portland
OREGON
Bend
Jordan Cove LNG
Coos Bay, OR
Pacific
Connector
Medford
Klamath
Falls
Malin
NWGA GAS OUTLOOK 2010

55

SENDOUT RUN	Key elements in SENDOUT modeling	Discussion
All Resources	Existing supply contracts, incremental supplies (peaking, annual, seasonal and citygate) from various receipt points (AECO, Rockies, Sumas, Station 2, Malin, as well as behind the citygate (satellite LNG). Incremental supplies also include propane, satellite LNG (behind citygate), imported LNG (Jordan Cove, Bradwood Landing), current upstream pipeline transport capacity, as well as proposed pipelines and extensions (Blue Bridge, Ruby, Pacific Connector, and Palomar). We also included Cascade's current Jackson Prairie storage accounts, our Plymouth LNG account, as well as the potential to obtain a third party's Jackson Prairie account, as well as AECO and Mist storage.	From this mix we should be able to develop the likely base case. We are still running sensitivities on the various pipeline projects. Currently Blue Bridge, accompanied with incremental NWP capacity seems to be selected. Malin exchanges seem to be preferred to capacity acquisition due to rate stacking with the Palomar and Ruby options. Satellite LNG facilities located within Cascade's distribution system may also be an attractive alternative to incremental pipeline capacity in areas where physical limitations at the gate stations would result in even higher costs associated with a pipeline solution. There may be additional advantages to such a strategy to the extent a facility could be strategically located on a portion of the distribution system that will eliminate or reduce distribution system constraints.
Limited Canadian Imports	Model contains all the elements of the Basecase, but incremental Annual AECO and seasonal Sumas resources will be unavailable to the model. Additionally, annual Sumas max is lowered from 100,000 to 50,000 dths. The intent to is to restrict the amount of Canadian imports by at least 20%	•Most believe that while imports may lessen, they will be available (at a price). •Natural gas is expected to be abundant for the foreseeable future •The other storage options may provide some other sourcing possibilities.
Blue Bridge With GTN backhaul and Palomar	Model contains all the elements of the Basecase, however, but includes the ability to backhaul from GTN-Malin to Palomar and then to NWP at Blue Bridge Sunstone was not available as a potential resource; Rockies gas had no choice but to flow on NWP.	•Rate stacking •Basis parity would mean this provides transportation diversity as opposed to supply diversity •GTN backhaul offering •Potential bottleneck at Stanfield and/or Malin
No Rockies price advantage	Model contains all the elements of the Basecase; however, all potential incremental resources are priced at NYMEX flat with no basis adder. In other words, incremental AECO, Sumas and Rockies all have the same price.	In this run, the model chose to increase the amount of imported LNG in Oregon as Canadian resources were restricted. Some interest was also shown in acquiring Ruby. We continue to run numerous sensitivities with varying levels of restrictions in order to see the impact to the portfolio.

Ruby Pipeline	Model contains all the elements of the Basecase; however, Ruby Pipeline is added as an additional resource. For modeling purposes we assume the $0.95 rate (the max rate identified in their tariff) The model is set up so that Ruby becomes an option to move Rockies gas to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates, likely in Central Oregon, although it is possible to move the gas to Stanfield for transport on NWP	•Rate stacking •Basis parity would mean this provides transportation diversity as opposed to supply diversity •GTN backhaul offering •Potential bottleneck at Stanfield and/or Malin
Pacific Connector	Model contains all the elements of the Basecase; however, Pacific Connector is added as an additional resource. In addition, we will add incremental LNG (Jordan Cove) as a potential resource. For modeling purposes we started with Pacific Connector transport priced at approximately 3 times the current NWP rate. The model is set up so that Pacific Connector becomes an option to move imported LNG to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates.	•Unknown if facility will ever get built •GTN backhaul offering •Rate stacking •Potential bottleneck at Stanfield and/or Malin
Palomar	Model contains all the elements of the Basecase; however, Palomar Pipeline is added as an additional resource. In addition, we will add incremental LNG (Bradwood Landing) as a resource. We will use the max rate identified in their tariff. The model is set up so that Palomar becomes an option to move imported LNG to GTN, where it would take incremental GTN capacity (backhaul) to move to Cascade's citygates. We also will look to see about using Palomar to backhaul to NWP near Portland and move supplies up BlueBridge or continue along NWP	•Unknown if facility will ever get built •GTN backhaul offering •NWP additional facilities needed? •Potential bottleneck at Washougal, Stanfield and/or Malin
AECO Storage	Model contains all the elements of the Basecase; however, AECO storage is added as a resource. The inventory is set at 300,000 dths, with daily withdrawal rights of 10,000 dths a day. This storage will be setup like the existing Jackson Prairie to be 100% full at the start of each heating season. The model is set up so that Canadian withdrawals can use incremental GTN capacity.	•Competition with Alberta for re-fill volumes •Rate stacking 57

Ruby Pipeline	Model contains all the elements of the Basecase; however, Ruby Pipeline is added as an additional resource. For modeling purposes we assume the $0.95 rate (the max rate identified in their tariff) The model is set up so that Ruby becomes an option to move Rockies gas to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates, likely in Central Oregon, although it is possible to move the gas to Stanfield for transport on NWP	•Rate stacking •Basis parity would mean this provides transportation diversity as opposed to supply diversity •GTN backhaul offering •Potential bottleneck at Stanfield and/or Malin
Pacific Connector	Model contains all the elements of the Basecase; however, Pacific Connector is added as an additional resource. In addition, we will add incremental LNG (Jordan Cove) as a potential resource. For modeling purposes we started with Pacific Connector transport priced at approximately 3 times the current NWP rate. The model is set up so that Pacific Connector becomes an option to move imported LNG to GTN, where it would require incremental GTN capacity (backhaul) to move to Cascade's citygates.	•Unknown if facility will ever get built •GTN backhaul offering •Rate stacking •Potential bottleneck at Stanfield and/or Malin
Palomar	Model contains all the elements of the Basecase; however, Palomar Pipeline is added as an additional resource. In addition, we will add incremental LNG (Bradwood Landing) as a resource. We will use the max rate identified in their tariff. The model is set up so that Palomar becomes an option to move imported LNG to GTN, where it would take incremental GTN capacity (backhaul) to move to Cascade's citygates. We also will look to see about using Palomar to backhaul to NWP near Portland and move supplies up BlueBridge or continue along NWP	•Unknown if facility will ever get built •GTN backhaul offering •NWP additional facilities needed? •Potential bottleneck at Washougal, Stanfield and/or Malin
AECO Storage	Model contains all the elements of the Basecase; however, AECO storage is added as a resource. The inventory is set at 300,000 dths, with daily withdrawal rights of 10,000 dths a day. This storage will be setup like the existing Jackson Prairie to be 100% full at the start of each heating season. The model is set up so that Canadian withdrawals can use incremental GTN capacity.	•Competition with Alberta for re-fill volumes •Rate stacking 58

2010 IRP Potential and Existing Supply Side Resources

NOTE: The rec/del points could potentially include Ruby, Palomar, BlueBridge, Pacific Connector, etc.
Will be updated when modeling complete.

MODEL NAME	CATEGORY	RECEIPT PT(S)	DELIVERY PT(S)	PRICE INDEX	DEMAND CHARGE	BASE/SWING	DEAL START DATE	DEAL END DATE	MDQ IN DTHS	INDEX DIFFERENTIAL	FIXED PRICE
FIRM IFSUM	ANNUAL	SUMAS	NWP, GTN	IFERC SUMAS		BASE	12/1/2007	3/31/2014	VARIABLE	$ 0.0547	
FIRM IF RM	ANNUAL	ROCKIES	NWP, GTN	IFERC ROCKIES		BASE	11/1/2008	3/31/2014	VARIABLE	$ 0.0375	
FIRM NYM NIT	ANNUAL	AECO	NWP, GTN	NYMEX HH		BASE	11/1/2012	2/28/2014	VARIABLE	$ 0.0150	
FIRM CGP NIT	ANNUAL	AECO	NWP, GTN	AECO (CGPR)		BASE	11/1/2009	3/31/2014	VARIABLE	$ 0.0161	
FIRM FX NIT1	SEASONAL	AECO	NWP, GTN	FIXED		BASE	4/1/2011	2/28/2013	VARIABLE		$ 5.4900
FIRM CGP ST2	SEASONAL	STATION 2	NWP, GTN	AECO (CGPR)		BASE	11/1/2009	4/1/2012	VARIABLE	$ 0.0467	
FIRM FX SUM	SEASONAL	SUMAS	NWP, GTN	FIXED		BASE	11/1/2010	10/31/2013	VARIABLE		$ 5.9800
PEAK 1	PEAKING	CITYGATE	NWP	GD SUMAS	0.05	SWING	12/1/2008	3/1/2012	15000	$ 0.1800	
PEAK 2	PEAKING	CITYGATE	NWP	GD SUMAS		SWING	11/1/2009	4/1/2012	15000	FLAT	
PEAK 3	PEAKING	SUMAS	NWP	GD SUMAS		SWING	4/1/2010	11/1/2010	30000	$ (0.0100)	
PEAK 4	PEAKING	SUMAS	NWP	GD SUMAS	0.03	SWING	11/1/2009	4/1/2012	5000	$ 0.0300	
FIRM I STAN	SEASONAL	STANIFIELD	NWP, GTN	IFERC SUMAS		SWING	11/1/2011	3/31/2014	VARIABLE	$ (0.4700)	
PEAK 5	PEAKING	AECO	NWP, GTN	AECO (CGPR)	0.1	SWING	12/1/2009	3/1/2010	5000	$ 0.0200	
FIRM FX NIT2	SEASONAL	AECO	NWP, GTN	FIXED		SWING	11/1/2009	2/29/2012	VARIABLE		$ 4.7800
FIRM FX ST2	SEASONAL	FIXED	NWP, GTN	FIXED		SWING	11/1/2009	12/1/2011	VARIABLE		$ 6.0800
FIRM GD ST2	SEASONAL	STATION 2	NWP, GTN	GD SUMAS		SWING	11/1/2010	4/1/2011	10000	$ 0.0500	
FIRM FX RM2	SEASONAL	ROCKIES	NWP, GTN	FIXED		SWING	11/1/2009	3/31/2013	VARIABLE		$ 5.5000
FIRM STR RM	ANNUAL	ROCKIES	NWP, GTN	FIXED IF IF RM < $		BASE	11/1/2009	11/1/2014	1000 - 2500		
FIRM STR SUM	SEASONAL	SUMAS	NWP, GTN	IFSUM -.25 W/FLR		SWING	11/1/2008	3/1/2011	5000		
FIRM CG NIT	ANNUAL	CITYGATE	GTN	AECO (CGPR)		BASE	11/1/2009	11/1/2014	VARIABLE	$ 0.3000	
FIRM GD SUM	SEASONAL	SUMAS	NWP, GTN	GD SUMAS		SWING	4/1/2010	10/31/2012	VARIABLE	$ 0.0250	
FIRM CG SUM	SEASONAL	CITYGATE	NWP	IFERC SUMAS		SWING	11/1/2009	3/1/2010	VARIABLE	$ 0.4200	
FIRM SPT SUM	SEASONAL	SUMAS	NWP, GTN	IFERC SUMAS		SWING	1/1/2010	INCREMENTAL	VARIABLE		
FIRM SPT NIT	SEASONAL	AECO	GTN	AECO (CGPR)		SWING	1/1/2010	INCREMENTAL	VARIABLE		
FIRM SPT RM	SEASONAL	ROCKIES	NWP, GTN	IFERC ROCKIES		SWING	1/1/2010	INCREMENTAL	VARIABLE		59

2010 IRP Potential and Existing Supply Side Resources

NOTE: The rec/del points could potentially include Ruby, Palomar, BlueBridge, Pacific Connector, etc. Will be updated when modeling complete.

MODEL NAME	CATEGORY	RECEIPT PT(S)	DELIVERY PT(S)	PRICE INDEX	DEMAND CHARGE	BASE/SWING	DEAL START DATE	DEAL END DATE	MDQ IN DTHS	INDEX DIFFERENTIAL	FIXED PRICE
INCR SUM A	ANNUAL	SUMAS	NWP, GTN	IFERC SUMAS		BASE	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR RM A	ANNUAL	ROCKIES	NWP, GTN	IFERC ROCKIES		BASE	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR NIT A	ANNUAL	AECO	GTN	AECO (CGPR)		BASE	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR SUM S	SEASONAL	SUMAS	NWP, GTN	IFERC SUMAS		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR RM S	SEASONAL	ROCKIES	NWP, GTN	IFERC ROCKIES		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR NIT S	SEASONAL	AECO	GTN	AECO (CGPR)		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR ST2	SEASONAL	STATION 2	NWP, GTN	GD SUMAS		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR STRU SU	ANNUAL	SUMAS	NWP, GTN	STRUCTURED		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR STRU RM	ANNUAL	ROCKIES	NWP, GTN	STRUCTURED		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR STRU AE	ANNUAL	AECO	GTN	STRUCTURED		SWING	11/1/2010	INCREMENTAL	VARIABLE	VARIABLE	
INCR SUM FX	ANNUAL	SUMAS	NWP, GTN	FIXED		BASE	11/1/2010	INCREMENTAL	VARIABLE		BETWEEN $5-$8
INCR RM FX	ANNUAL	ROCKIES	NWP, GTN	FIXED		BASE	11/1/2010	INCREMENTAL	VARIABLE		BETWEEN $5-$8
INCR NIT FX	ANNUAL	AECO	GTN	FIXED		BASE	11/1/2010	INCREMENTAL	VARIABLE		BETWEEN $5-$8
INCR MAL	SEASONAL	MALIN	BACKHAULS NWP, GTN	MALIN		SWING	11/1/2011	INCREMENTAL	VARIABLE	VARIABLE	
SAT LNG	SEASONAL	ZONAL	ZONAL	NYMEX HH		SWING	11/1/2012	INCREMENTAL	VARIABLE	VARIABLE	
IMP LNG NOR	SEASONAL	PALOMAR	BACKHAULS NWP, GTN	NYMEX HH		SWING	11/1/2015	INCREMENTAL	VARIABLE	VARIABLE	
IMP LNG SOR	SEASONAL	PACIFIC CONNECTOR	BACKHAULS NWP, GTN	NYMEX HH		SWING	11/1/2016	INCREMENTAL	VARIABLE	VARIABLE	
SAT PROP	SEASONAL	ZONAL	ZONAL	NYMEX HH		SWING	11/1/2011	INCREMENTAL	VARIABLE	VARIABLE	
INCR CG NWP	SEASONAL	CITYGATE	NWP	NYMEX HH		SWING	11/1/2011	INCREMENTAL	VARIABLE	VARIABLE	
INCR CG GTN	SEASONAL	CITYGATE	GTN	NYMEX HH		SWING	11/1/2011	INCREMENTAL	VARIABLE	VARIABLE	60

EXISTING AND POTENTIAL ADDITIONAL STORAGE RESOURCES

STORAGE	Model Name	Type	Location	Pipeline Transport Required	Evergreen	Start	Contract Expiration	Lead Time	Max Cap	WD MDQ	Fuel Inj < 3%	SVDD	D2 RATE > $0.05 < $0.15
STORAGE 1	JP-1	Undergound	Jackson Prairie	Yes	Yes	1994	2014	NA	604,351	16,789	YES	SGS	YES
STORAGE 2	JP-EXP	Undergound	Jackson Prairie	Yes	Yes	2009 (full access 2010)	2060	NA	350,000	30,000	YES	SGS	YES
STORAGE 3	LNG	LNG	Plymouth	Yes	Yes	1994	2014	NA	562,207	60,000	YES	SGS	YES
STORAGE 4	AECO STORAGE	Undergound	AECO	Yes	NA	2013	2030	NA	300,000	10,000	YES	AECO C STRG	YES
STORAGE 5	MIST STORAGE	Undergound	Mist	Yes	NA	2013	2030	NA	300,000	10,000	YES	MIST	YES
STORAGE 6	JP-SURPLUS	Undergound	Jackson Prairie	Yes	Yes	2012	2030	NA	300,000	5,000	YES	SGS	YES

POTENTIAL ADDITIONAL PIPELINE TRANSPORT RESOURCES

Model Name	Start Date	End Date	Daily MDQ	Description	Cost Dths	Lead Time	Pipeline	RMIX MAX	RMIX MIN	VARIABLE < $.10	FUEL < 3%
INCR-GTN	Nov-10	Oct-24	TBD	AECO NIT, Foothills to Kingsgate	NOVA, Foothills, GTN		NOVA, Foothills, GTN	UP TO 50,000		YES	YES
INCR-NWP	Nov-10	Oct-24	TBD	Sumas to WA and OR citygates	NWP Rate X 3		NWP	UP TO 200,000		YES	YES
INCR-MAL	Oct-11	Dec-30	TBD	Malin backhaul to Central OR and Stanfield Interconnect	GTN Rate	2 years	GTN	UP TO 50,000		YES	YES
BLUEBRDIGE	Nov-11	Dec-30	TBD	Stanfield Interconnect to I-5 Corridor	Precedent Agmt	2 years	NWP	UP TO 50,000		YES	YES
RUBY XPORT	Nov-12	Dec-30	TBD	Opal Hub to Mailin	NWP Rate X 3	< 2 years	RUBY	UP TO 50,000		YES	YES
PALOMAR XPORT	Nov-15	Dec-30	TBD	Madras OR to Molalla OR (bi-directional)	NWP Rate X 3	> 3years	PALOMAR	UP TO 50,000		YES	YES
PAC CONNECT	Nov-15	Dec-30	TBD	Jordona Cove OR to Malin	NWP Rate X 3	> 4 years	PAC CONNECT	UP TO 50,000		YES	YES

Other thoughts, questions, concerns…

- Are there other ideas or concerns that you feel need to be addressed?
- Are there other alternatives we should consider?

Adjourn

2010 Integrated Resource Plan

Technical Advisory Group Meeting

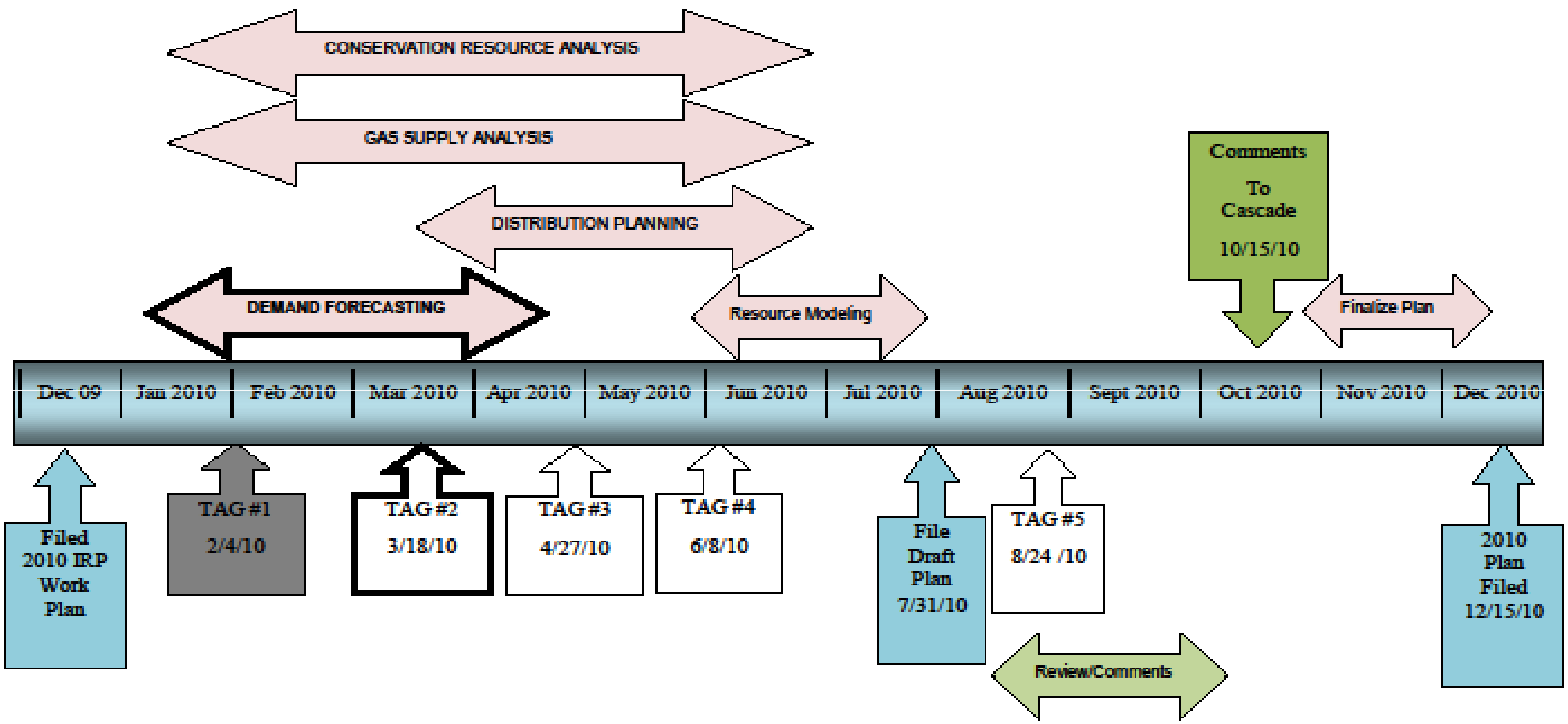
June 8, 2010

Agenda

- Introductions
- Review Conservation Objectives
- Washington Conservation Technical Potential Scenarios
- Carbon Legislation & Impact Scenarios
- Preliminary Conservation Curves

CASCADE NATURAL GAS CORPORATION

2010 IRP Workplan



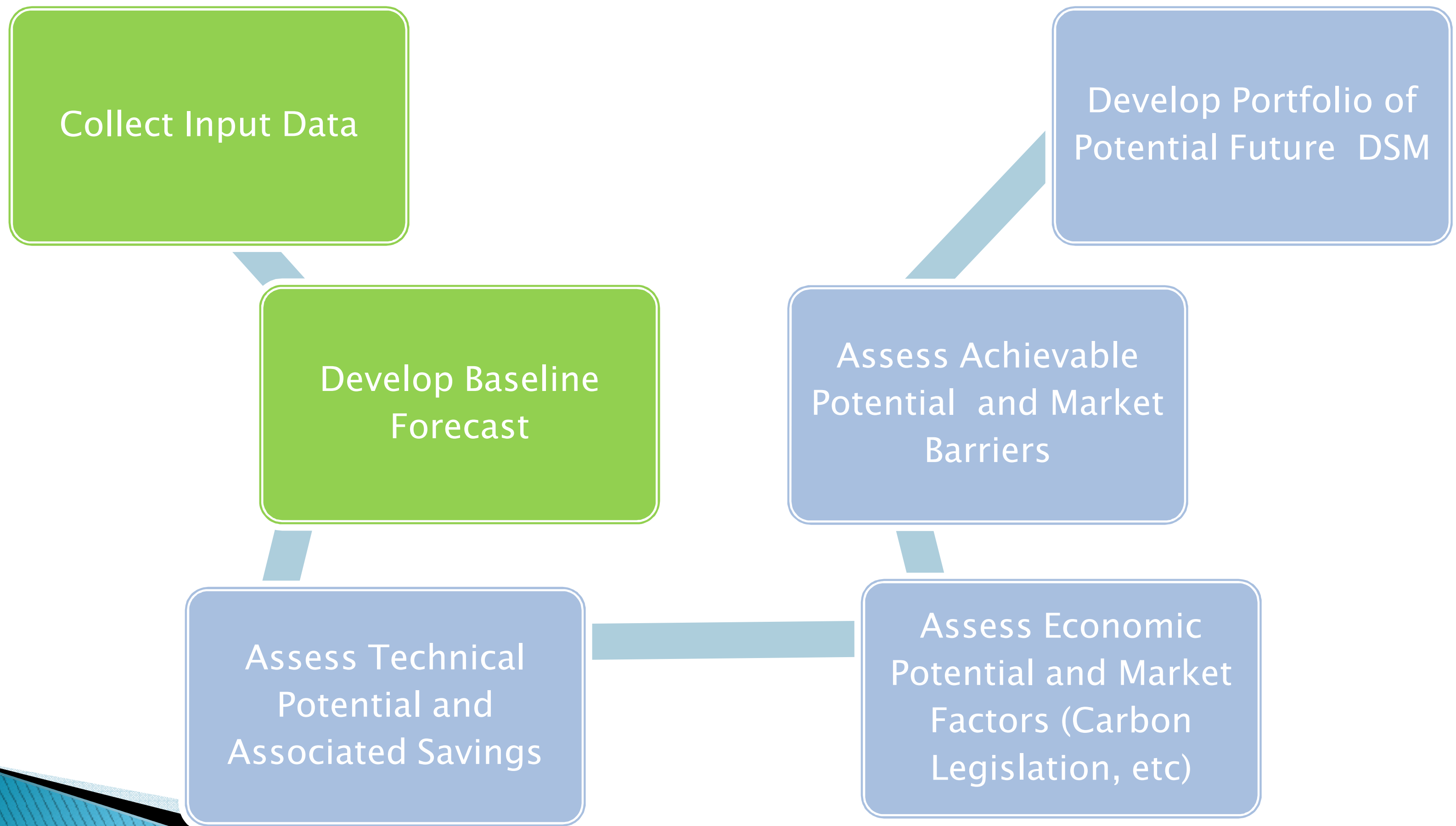
Cascade Natural Gas Corporation

DSM Objective

Acquire <u>cost-effective</u> demand side resources that meet the needs of the Company's core customers.

Cost effectiveness based on both Total Resource Cost and Utility Cost Tests

Demand Side Management– Analysis Process



Baseline Development and Analysis of Potential

- **Technical Potential**
  - Quantified the current energy used by sector and customer type
  - Estimated energy consumption by end use for each customer type
  - Applied the forecasted growth rate to estimate the customer base available in future years
  - Reviewed information on specific measure for applicability to Cascade's customers

- **Deemed energy savings and associated costs**
  - Identified deemed savings by climate zone
  - Provided technical and potential supply curve savings for out to 2030

Technical Potential Update

- Began with 2008 IRP Assessment

- Updated based on:
  - Availability—impacted by customer growth forecast
  - Measure cost—will be updated where applicable for change in installed cost
  - Estimated Deemed savings: Update based on Cascade's M&V (2008 program results)

Technical Potential Update (cont)

- Screen Based on Estimated Avoided Costs
- Impacts
  - Long-Term Gas Price Forecast
    - Currently estimated same or down from 2008 IRP
  - Uncertainties
    - Code Changes (removes from utility's portfolio)
    - Carbon Costs

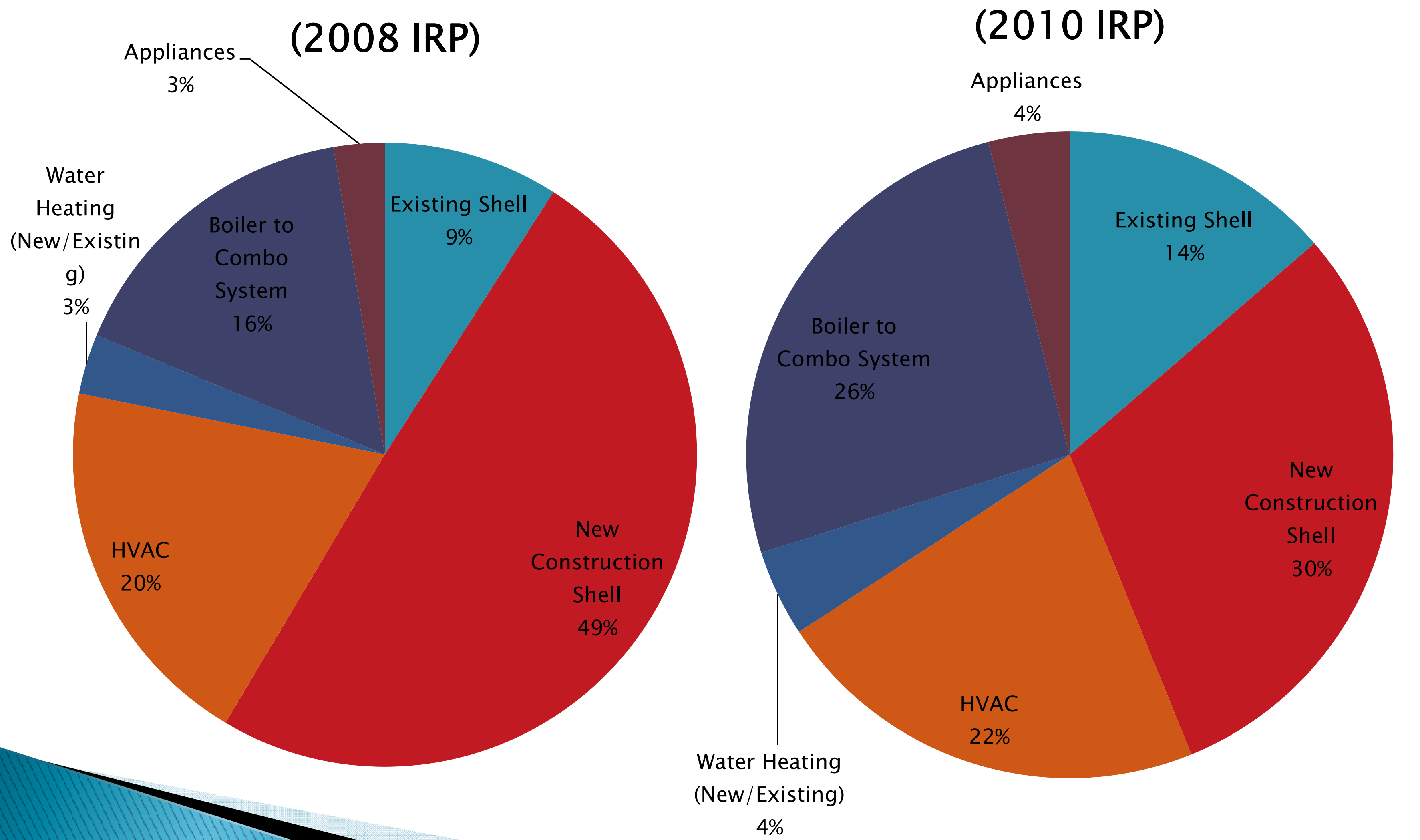
WA Residential Technical Potential -Draft Result

2030 Technical Potential Screened @ .85 levelized cost/therm

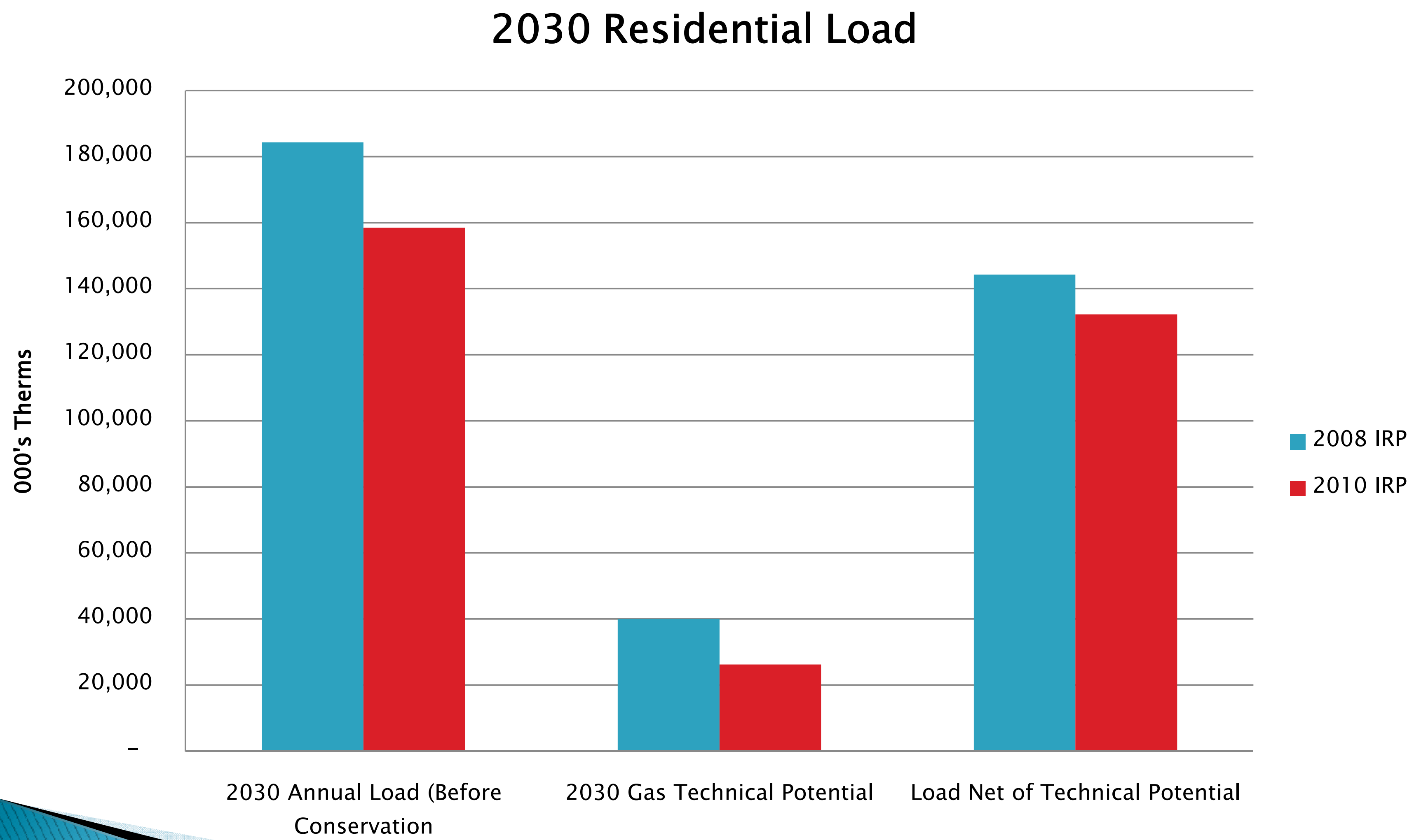
	2008	2010
Existing Shell	3,632,692	3,585,461
New Construction Shell	**19,800,893**	**7,920,357**
HVAC	7,852,786	5,753,797
Water Heating (New/Existing)	1,237,567	1,135,937
Boiler to Combo System	6,454,454	6,777,258
Appliances	1,056,709	1,065,143
	40,035,102	26,237,953

Impact due to change in Demand Forecast (Customer) forecast

Residential Technical Potential – Thru 2030 (WA Only)



Technical Potential–Residential



Screening is KEY!

- Estimated Avoided Costs used to screen for packages
- Initially Screened for Measures @ levelized costs of $.85 or Less
- Additional Bundles of "Potential"
  - Screened @ $1.00/therm
  - Screened @ $1.50/therm
  - Screened @ $2.00/therm
  - $2.50/therm and greater

WA Conservation Bundles (Residential)

	Screened at Levelized cost/therm of						
	$0.75	$0.85	$1.00	$1.50	$2.00	$2.50	>$ 2.50
Existing Shell	3,585,461	3,585,461	3,585,461	3,585,461	3,585,461	3,881,528	3,881,528
New Construction Shell	5,776,721	7,920,357	9,365,736	9,365,736	9,365,736	9,365,736	9,365,736
HVAC	4,482,246	5,753,797	7,698,678	7,892,797	8,249,568	8,249,568	8,249,568
Water Heating (New/Existing)	155,904	1,135,937	1,135,937	1,878,664	1,878,664	3,484,908	7,099,760
Boiler to Combo System	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258	6,777,258
Appliances	1,065,143	1,065,143	1,065,143	1,065,143	1,065,143	1,065,143	1,065,143
	21,842,733	26,237,953	29,628,213	30,565,059	30,921,830	32,824,141	36,438,992

Technical to Achievable

- Technical Potential: The estimate of all energy savings that could be accomplished without the influence of any market barriers such as costs and customer awareness

- Achievable Potential: “a realistic assessment of what can be expected taking into account not all consumers can be persuaded”

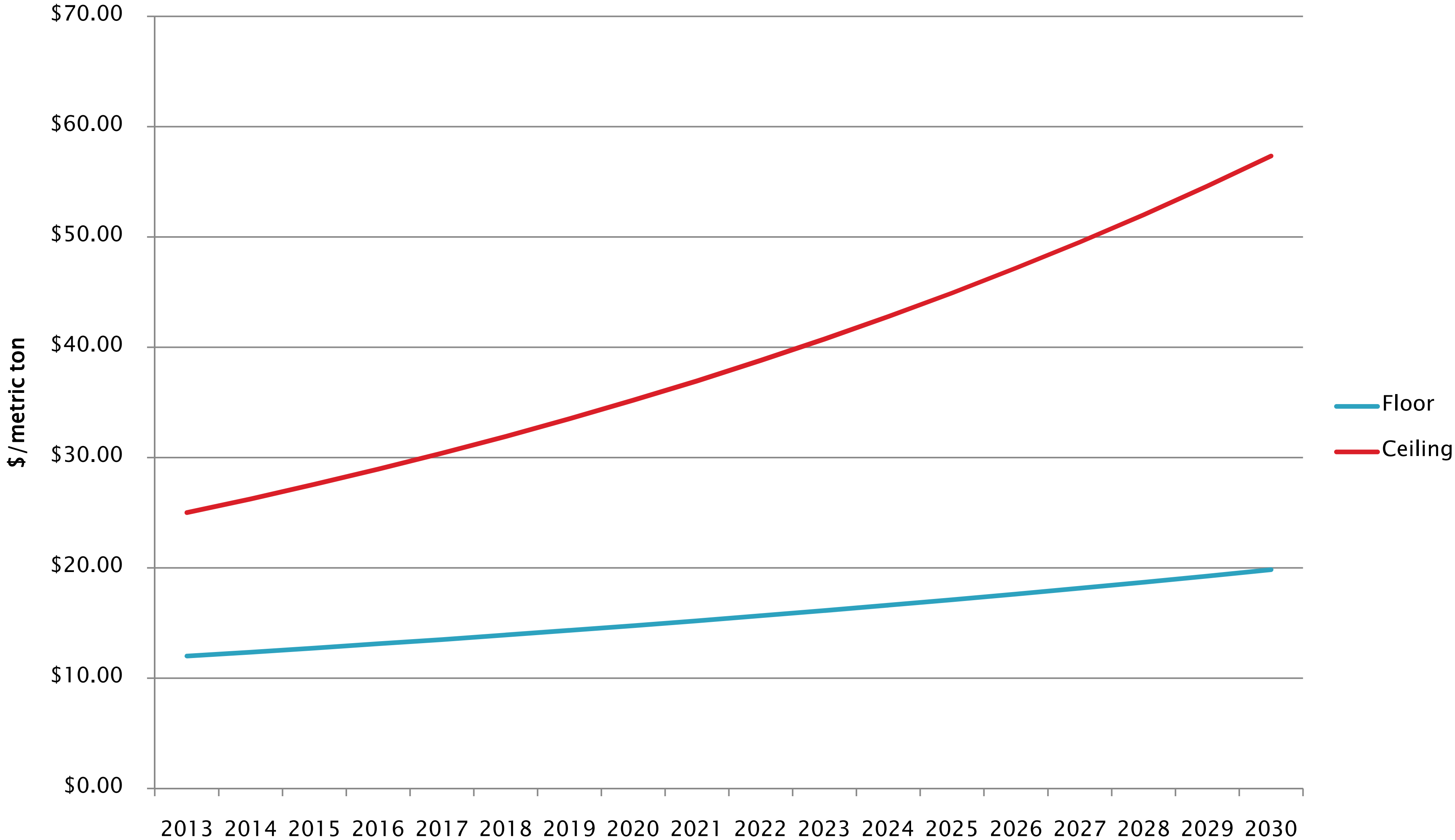
LET's Talk Carbon!

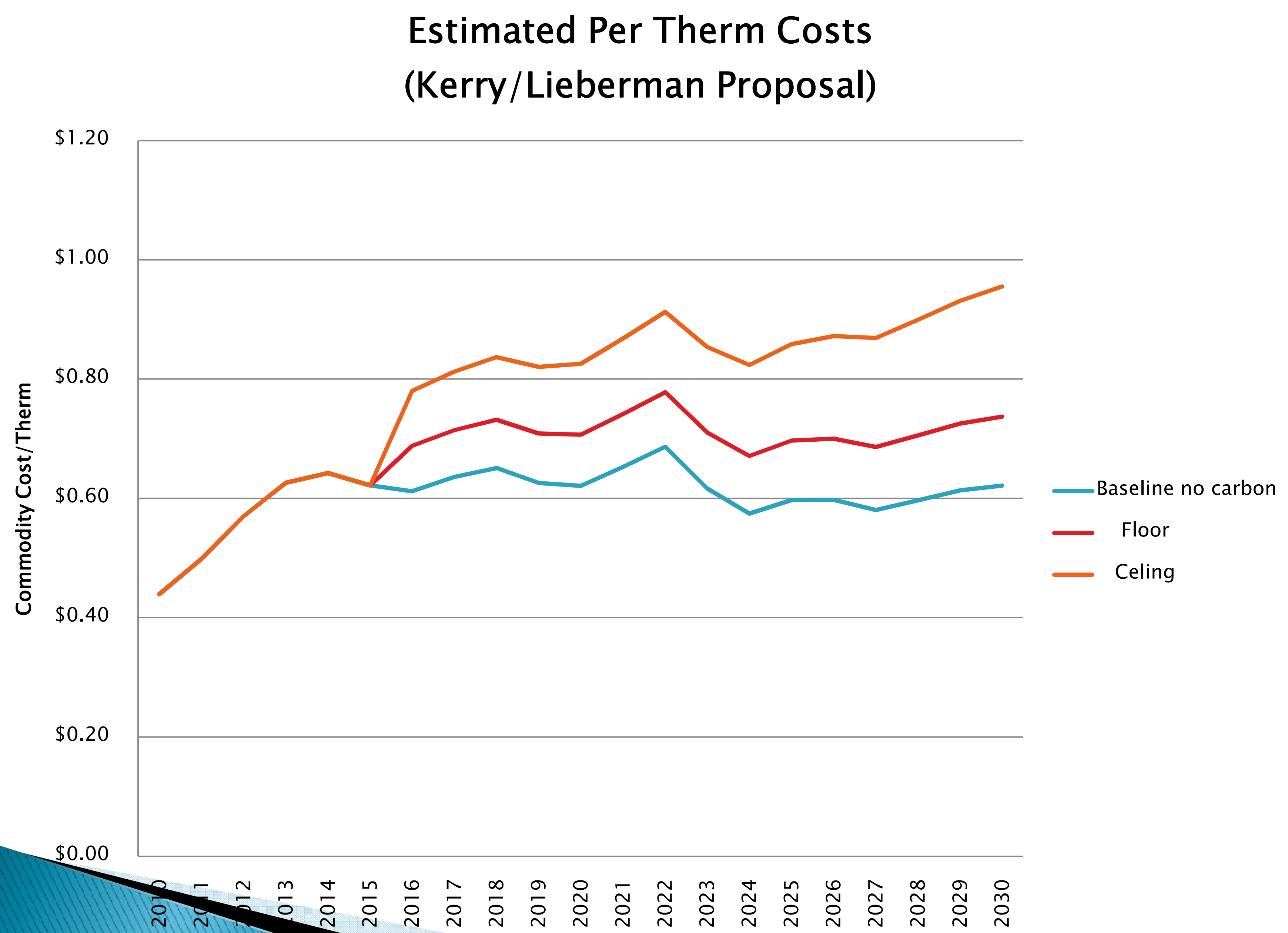
- Carbon Legislation is likely to have the biggest potential impact on Avoided Costs
- Cap & Trade or Carbon Tax, essentially the same for an LDC
  - LDC's deliver Gas and every molecule has an Emission that would result in a cost (tax)
  - Allowances under a Cap & Trade just lower the amount of the credits that would need to be purchases
  - LDC's do not have "carbon-free" alternatives for their portfolio (no wind/solar)

Kerry/Lieberman "Draft" Bill

- Carbon costs
  - Floor $12 to increase 3% annually (plus CPI)
  - Ceiling $25 to increase 5% annually (plus CPI)
- LDC's 9% of "Total" Allowances
  - Assumed level of emissions and initial level of allowances matched
  - Does not factor for growth in demand
  - Allowances decrease by 20% from 2005-2020
- Timing
  - LDC's 2016
  - Timeframe for passage of bill uncertain

Estimated Carbon Allowance Costs
(Kerry/Lieberman Draft Legislation)




Estimated Per Therm Costs
(Kerry/Lieberman Proposal)
Commodity Cost/Therm
$1.20
$1.00
$0.80
$0.60
$0.40
$0.20
$0.00
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Baseline no carbon
Floor
Celing

18

Issues to Consider

- Building Code Impacts:
  - Do utilities "still" include in Potential and resulting targets?
- Carbon Scenarios
  - At what point do gas utilities incorporate carbon costs into TRC screening
  - Are the costs for carbon "known & measurable"

Adjourn

2010 Integrated Resource Plan

Technical Advisory Group Meeting

August 24, 2010

Agenda

- Introductions
- Price Forecast Update
- Preliminary Modeling Results
- Review Key Findings
- Avoided Cost Impacts
- Questions/Answer Format

Natural Gas Price Forecast

Price volatility has become an on-going factor in the natural gas industry since 2005. Prices in the natural gas market have continued to be volatile. Prices started climbing in January 2008 and kept rising through the spring and early summer, even though historically prices tend to decline after the end of the heating season. However, as of the time of this writing, the market prices have dropped by more than 50% from a high of $13.00 in early July 2008. Demand, oil price volatility, the global economy, electric generation, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. It is impossible to accurately predict what future natural gas prices will be. However, Cascade has considered price forecasts from several sources, such as Wood Mackenzie, Energy Information Agency, the Financial Forecast Center's forecast, as well as our observations of the market to develop our low, base and high price forecast.

Development of a Henry Hub price forecast

Current Market: Since pricing on the market is heavily influenced by Henry Hub prices, we closely monitor the market trend. At we developed the price forecast for the IRP, the market was in the process of falling after reaching the highs of July. While not a guarantee of where the market will ultimately finish, it is the most current information available that provides some direction as to future market prices. On a daily basis, we can see where Henry Hub is trading and how the future basis differential in our physical supply receiving areas (Sumas, AECO, Rockies) is trading.

Wood Mackenzie: Wood Mackenzie publishes a long-term price forecast each quarter to subscribing customers. This forecast is broken down by month through the planning horizon and includes Henry Hub as well as basis differentials for our receiving areas.

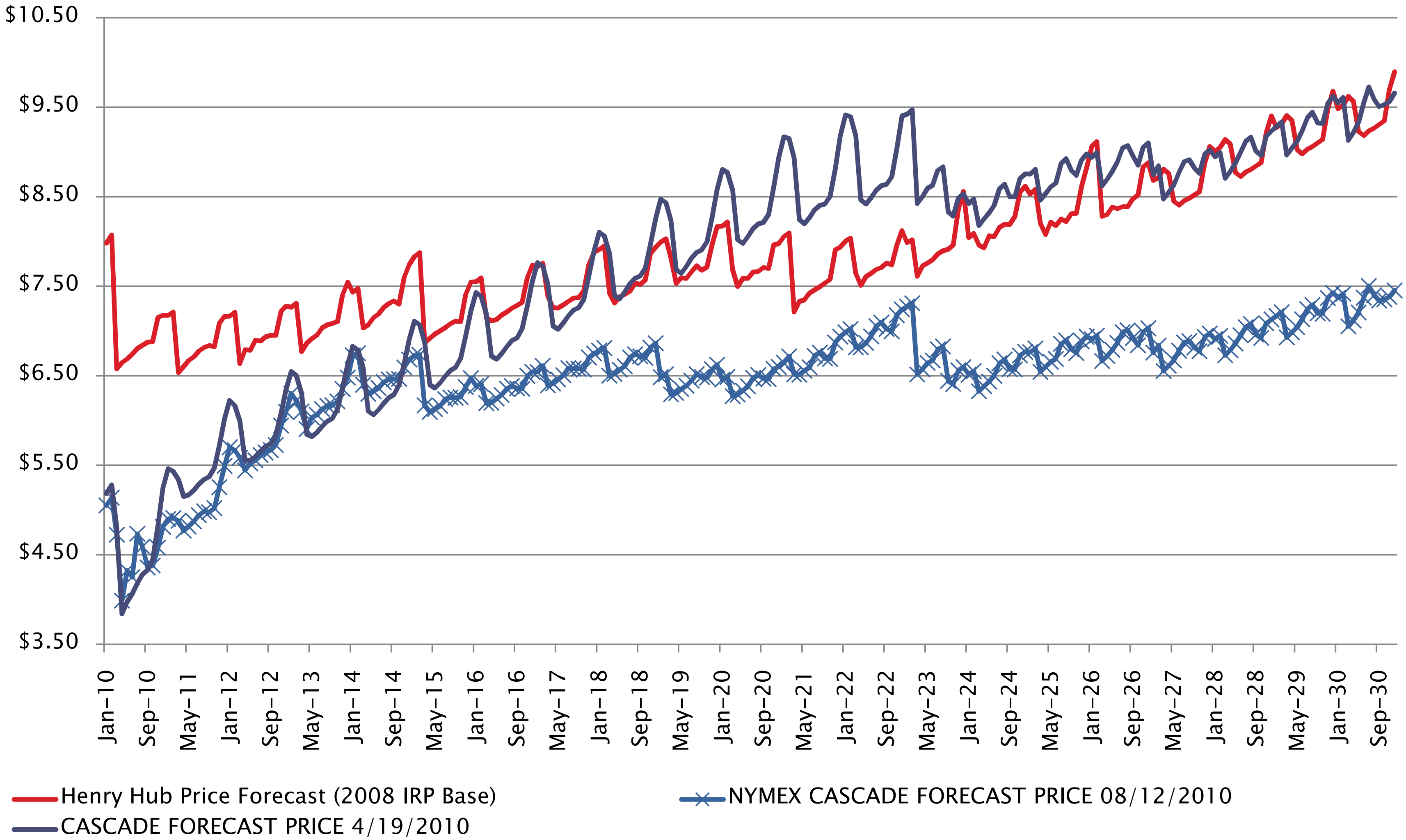
Energy Information Administration (EIA): We utilized the EIA price forecast. It should be noted that EIA's forecast is not always as current as the most recent market activity. Further, EIA forecast provides monthly breakdowns in the short term, but longer term forecast are by year. Given Cascade's load profile and the need for more winter gas than summer, we develop a pattern based on the market monthly forward prices to create a long-term, monthly Henry Hub price.

The Financial Forecast Center forecast: The Financial Forecast Center was a service of Market Research International and Applied Reasoning, Inc. Financial Forecast Center, LLC was split off from Applied Reasoning, Inc. in 2005 to focus on the creation and publishing of market forecasts while Applied Reasoning, Inc. focuses on the development of artificial intelligence software. This price forecast is available by year through the early portion of the planning horizon, but monthly breakdowns are available.

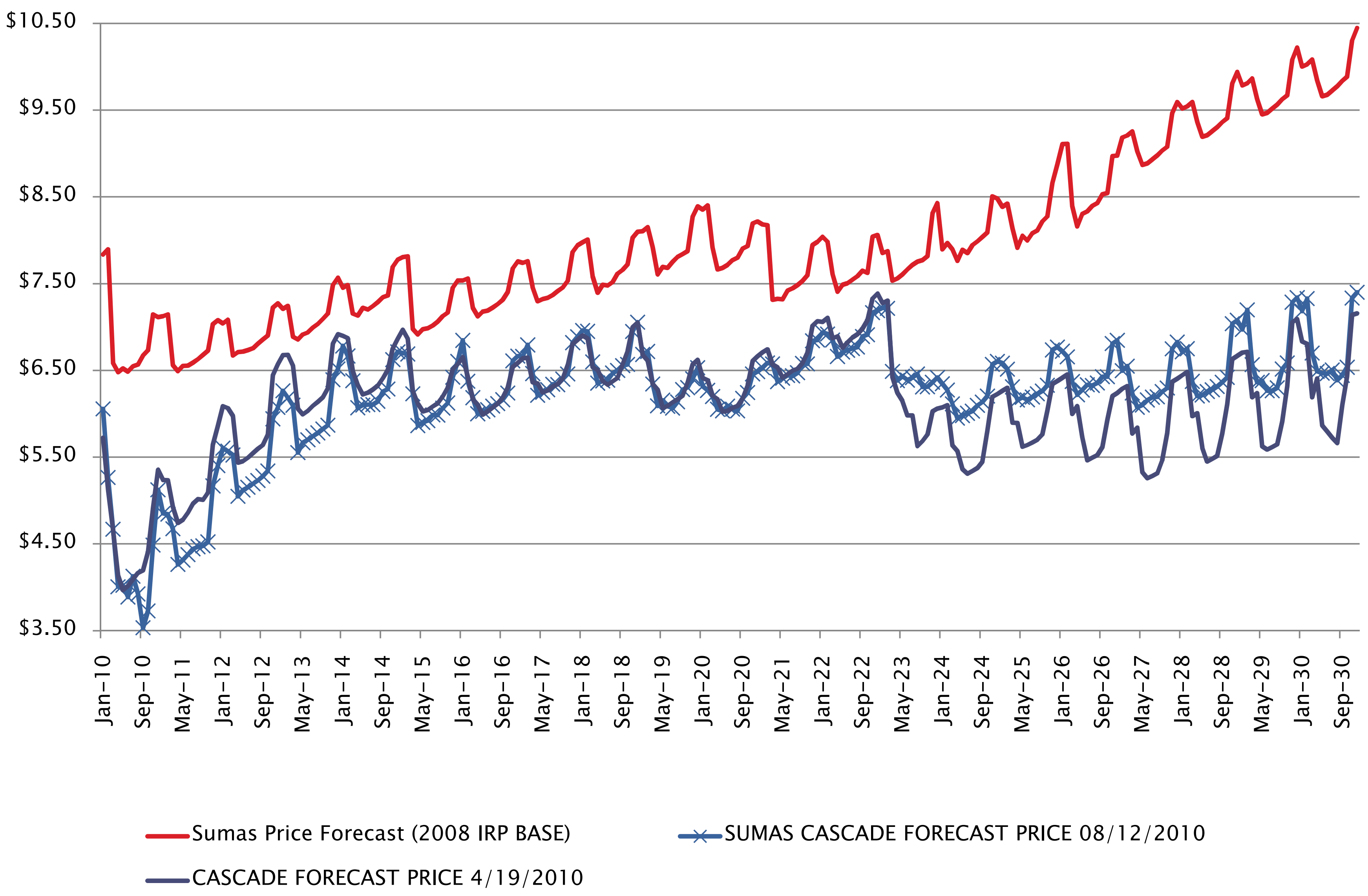
With a monthly Henry Hub price determined for the above sources, we assigned a weight to each source to develop the monthly Henry Hub price forecast for the planning horizon. At the time the price forecast was developed the Financial Forecast Center forecast was significantly lower than the Wood MacKenzie forecast and the forward market. Given the significantly higher future prices at the time versus the Comptroller forecast, we decided to severely limit the Financial Forecast Center from our weighted average. In recently years, EIA forecast has often been lower than the final monthly price, but it is still a respected industry barometer of prices so they were given a weight of approximately 40%. As we pointed out before, while current market is not necessarily going to accurately predict the final market price, it is often a reliable indicator; therefore we gave our market assessment some weight based on nearness to term. The weights at this point in time are as follows:

	Current	Wood	Financial	EIA
2010	80%	15%	1%	4%
2011	70%	19%	1%	10%
2012	60%	24%	1%	15%
2013	50%	25%	1%	24%
2014	33%	33%	0%	33%
2015	25%	40%	0%	35%
2016	8%	54%	0%	39%
2017	8%	54%	0%	39%
2018	8%	54%	0%	39%
2019	8%	54%	0%	39%
2020	8%	54%	0%	39%
2021	8%	54%	0%	39%
2022	8%	54%	0%	39%
2023	0%	60%	0%	40%
2024	0%	60%	0%	40%
2025	0%	60%	0%	40%
2026	0%	60%	0%	40%
2027	0%	60%	0%	40%
2028	0%	60%	0%	40%
2029	0%	60%	0%	40%
2030	0%	60%	0%	40%

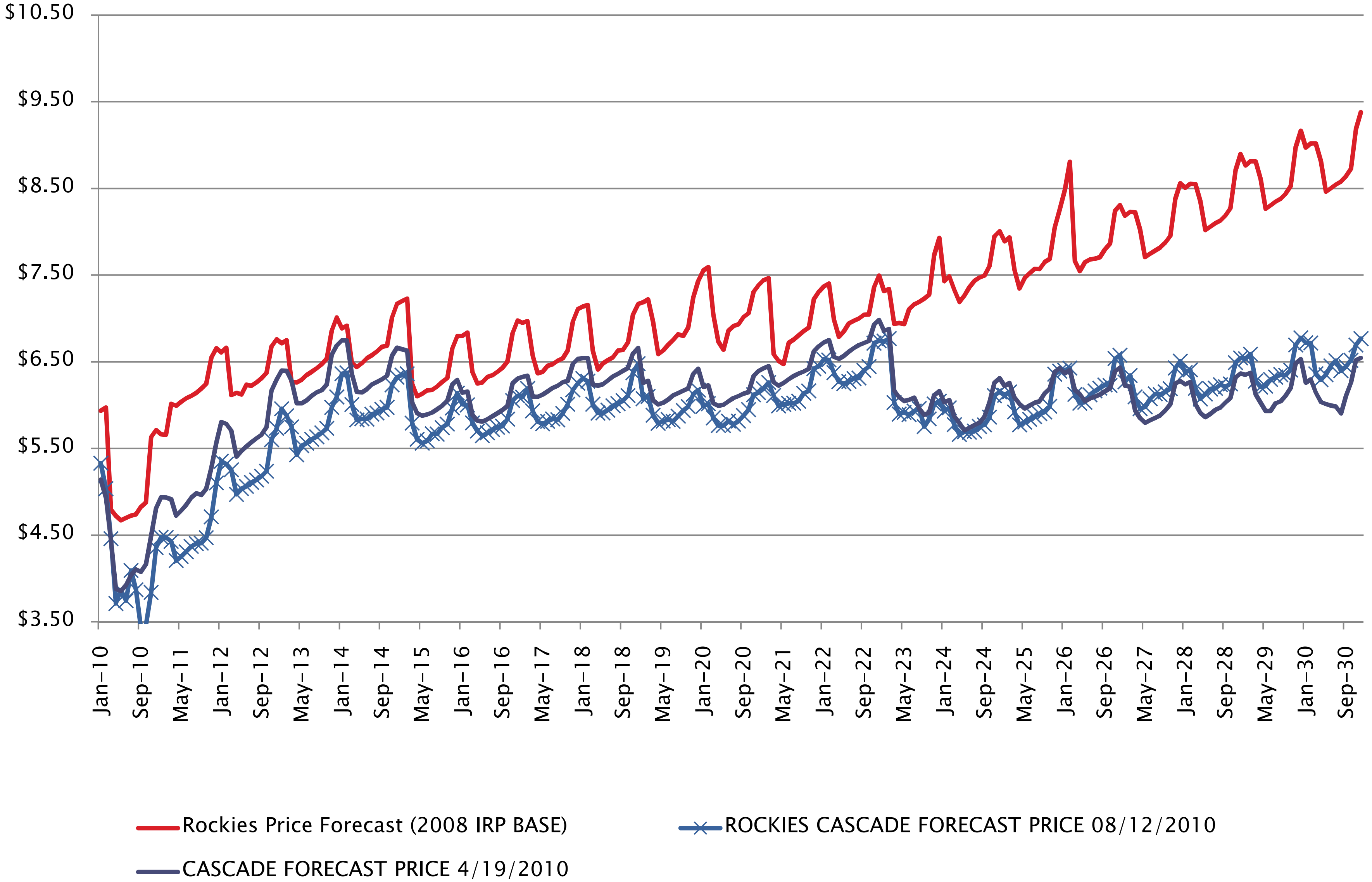
NYMEX HH Price Forecast Comparison 2008 vs 2010



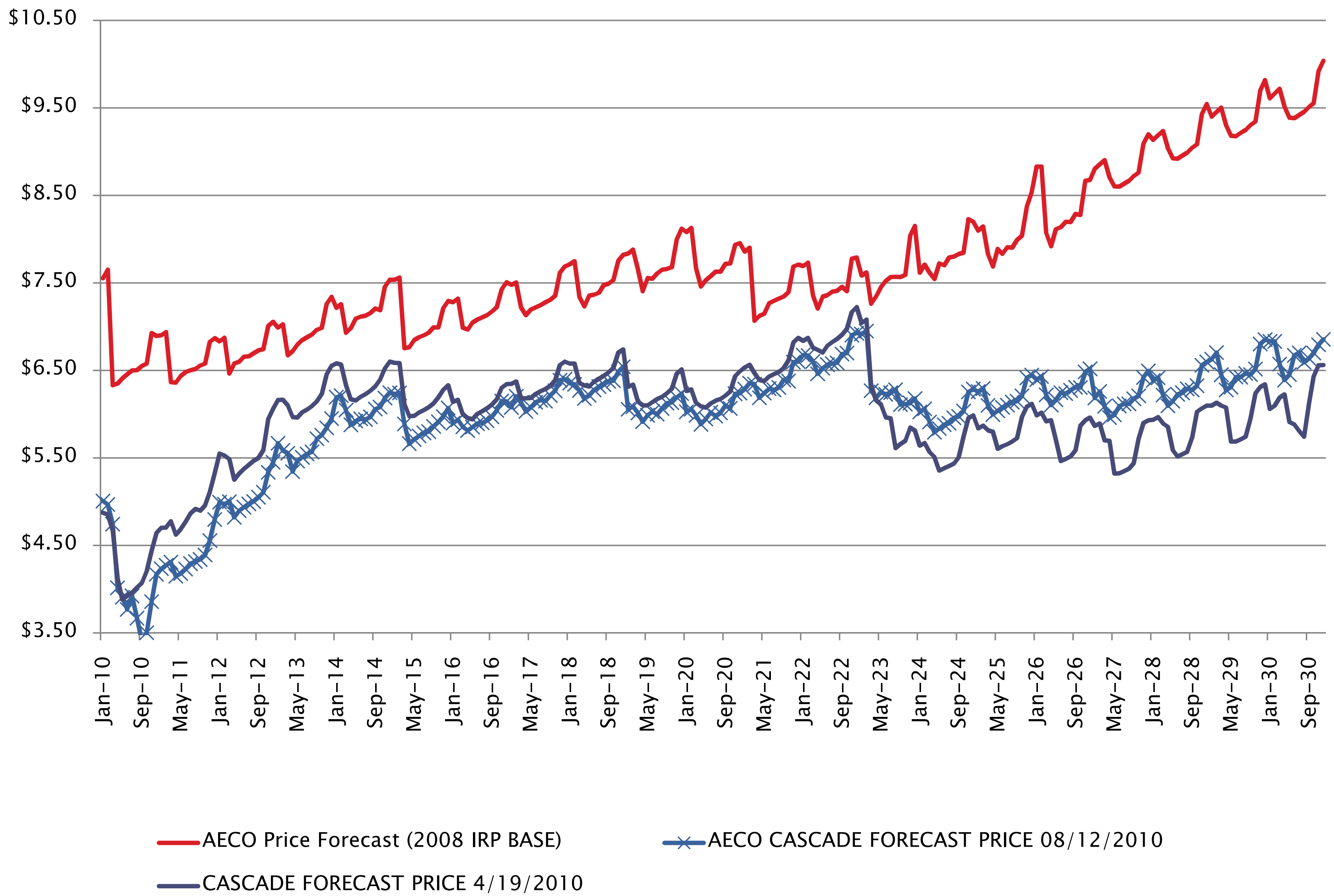
Sumas Price Forecast Comparison 2008 vs 2010



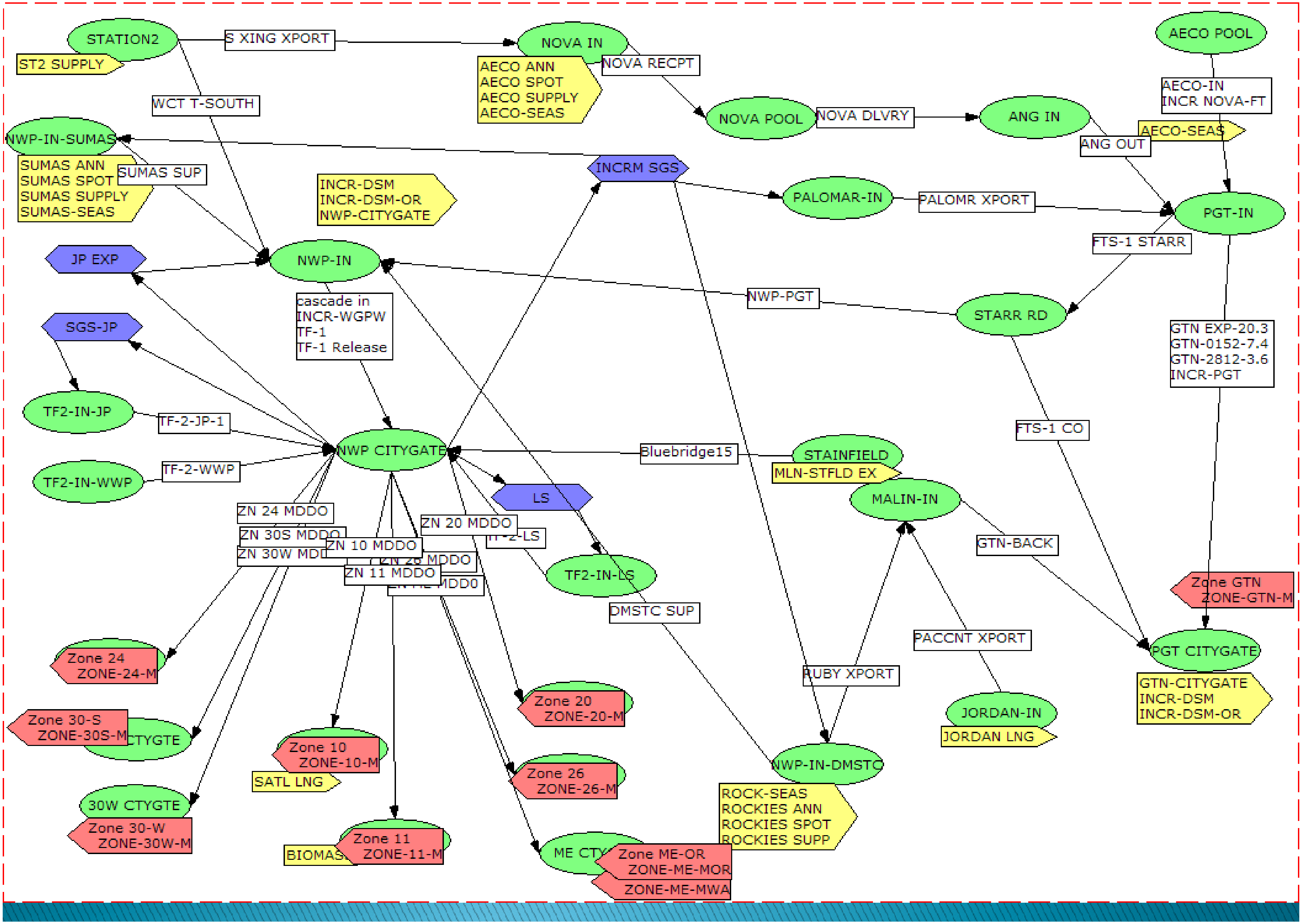
Rockies Price Forecast Comparison 2008 vs 2010



AECO Price Forecast Comparison 2008 vs 2010



SENDOUT NETWORK DIAGRAM



Optimization Modeling
(see handout)

- Modeling Runs
  - Scenarios/Inputs
  - Preliminary “Preferred Portfolio”
- Initial Conclusions

Avoided Costs--Baseline (see handout)

- With 10% Conservation Credit
  - 30 Year Avoided Costs$10.92 vs $13.20
  - Cost Effectiveness Limit $.64 vs $.78/therm
- With 15% Conservation Credit
  - 30 Year Avoided Costs$11.45 vs $13.20
  - Cost Effectiveness Limit $.68 vs $.78/therm

Avoided Costs—Carbon impact (see handout)

- 6 scenarios ranging from $12/ton to $30/ton
  - Assume starts in 2016 (consistent with WCI)
  - Assumes 3.5% annual increase in costs for inflation
  - Assumes NO ALLOWANCES

Avoided Costs- Carbon Impact (cont)

- $12/Ton Scenario
  - 30 Year Avoided Costs increase by $.98 to $11.90
  - Cost Effectiveness Limit increases by .06 to $.70/thm
- $30/Ton Scenario
  - 30 Year Avoided Costs increase by $1.86 to $12.78
  - Cost Effectiveness Limit increases by .11 to $.75/thm

Adjourn

Appendix A-3

IRP Guidelines & Rules

WAC 480-90-238 Integrated resource planning.

Each natural gas utility regulated by the commission has the responsibility to meet system demand with the least cost mix of natural gas supply and conservation. In furtherance of that responsibility, each natural gas utility must develop an "integrated resource plan."

<u>Content</u>. At a minimum, integrated resource plans must include:

(a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.

Section 3 describes the range of forecast of demand for the 20-year planning horizon. The text provides a range of forecasts that encompass the anticipated forces, both economic and weather-driven, that will impact the load forecasts over the planning horizon. The range of forecasts implicitly incorporates changes in the number, type and efficiency of natural gas end-uses as reflected in the changing use/customer figures over the planning horizon.

(b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.

Section 6 of the Plan details the company's demand side resource alternatives. The section includes an assessment of technically feasible improvements in the efficient use of natural gas. The detailed list of measures and their savings potential within Cascade's service territory is included in Appendices D-3 and D-4 of the Plan

(c) An assessment of conventional and commercially available nonconventional gas supplies.
(d) An assessment of opportunities for using company-owned or contracted storage.
(e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.

Section 5, the supply resource section, includes a discussion of the supply side resource options available including an assessment of conventional and commercially available nonconventional gas supplies, an assessment of opportunities for additional company-owned and contracted storage, and assessment of both existing and future pipeline transmission alternatives for meeting Cascade's load requirements. Appendix E contains the detailed list of resources evaluated in the integration model.

(f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.

Section 7, the integration section, provides a comparative evaluation of the cost of the various resource options on a consistent and comparable method. The company believes that all resources described in this IRP have been evaluated on a consistent and comparable basis through the use of its optimization model.

(g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.

Explanation: The resource integration section describes the integration of the demand forecast and resource evaluations into a long range resource plan and describes the Company's strategies to reliably meet current and future needs at the lowest reasonable cost to Cascade's ratepayers. According to WAC 480-90-238, "Lowest reasonable cost" means

"the lowest cost mix of resources determined through a detailed and consistent analysis of a wide range of commercially available sources. At a minimum, this analysis must consider resource costs, market-volatility risks, demand-side resource uncertainties, the risks imposed on ratepayers, resource effect on system operations, public policies regarding resource preference adopted by Washington state or the federal government, the cost of risks associated with environmental effects including emissions of carbon dioxide, and the need for security of supply."

Cascade believes all resources described in this IRP have been evaluated on a consistent and comparable basis through the use of its optimization model. Uncertainty has been considered in each component of this plan. The demand forecast includes a reasonable range of uncertainty as quantified in the low, medium and high load growth scenarios along with the additional simulation analysis calculated through the Monte-Carlo functionality that assesses the impacts of weather on the load forecasts. The demand side and supply side resource sections describe relative uncertainties regarding reliability, cost and operating constraints and external costs. Uncertainties associated with the environmental effects of carbon emissions have been discussed in detail and and an analysis of the potential impacts of carbon adders on the portfolio has been assessed. The company, through its analysis of limited Canadian supplies has identified alternatives to address concerns regarding security of supply. Price volatility and market risks and their impacts on the Company's long-term resource portfolio have been assessed through the use of the monte-carlo functionality of the Sendout model.

(h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.

Section 8 includes the 2010 2-Year Action Plan that describes the specific actions the utility will take to implement the long-range integrated resource plan during the next two years

(i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.

Appendix I reports on the Company's progress in meeting its 2008 2-Year Action Plan goals.

Timing. **Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.**

On December 15, 2009, the company submitted its detailed work plan which outlined the content of the plan to be developed and the methods to be used for assessing potential resources.

Cascade's 2010 Integrated Resource Plan will be filed with the WUTC on December 15, 2010.

Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.

The work plan identified a preliminary schedule for the Company's Technical Advisory Group meetings and outlined the timing of the filing of the Draft plan in order to allow the parties to provide comments before submission of the Plan on the December 15, 2010.

To involve public interests in the development stages of this IRP, Cascade has a Technical Advisory Group (TAG). Three meetings were held to discuss the major IRP topics including the key inputs demand forecast, distribution system planning, demand side resources, supply side resources, and resource integration and uncertainty analysis.

The TAG meetings were helpful to Cascade as questions were answered and varying points of view were explored. Appendix A contains an outline of the meeting content , a list of participants, and copies of the meeting presentation materials. Additionally, customers and interested parties were invited to comment on Cascade's Draft 2010 IRP. The company has provided for a month-long commenting period prior to publication of the 2010 Plan. Copies of the written comments will be included in Appendix A-4 of the final document. Cascade will make modifications to its Plan to address the recommendations received and where the recommendations cannot specifically be addressed, the recommendations will be incorporated into the Company's 2-year action plan.

Appendix A-4

Comments on Draft IRP

Comments from WUTC Staff :

"Cascade's avoided cost calculations are meant to model the marginal cost of natural gas usage incremental to the forecasted demand. This concept is important to assessing the appropriate level of demand-side management efforts. The Company's inclusion of an "incremental cost advantage for conservation such as price certainty and hedge value against future carbon costs" is an important and necessary component of avoided costs and Staff is encouraged to see its incorporation. The Basecase scenario avoided cost of $11.66 for 30-year measure and the cost-effectiveness limit of 69 cents per therm is adequate given the current market conditions."

Page 17, last paragraph, please elaborate as to what Cascade considers statistically valid, for the"past weather soured from NOAA" , is this the 30 year normal computed by NOAA every ten years?

Page 23, top table, what is causing the jump in the high case from 2015 to 2025?

Page 28, where is table 4-1?

Typo on page 39, Energy Information Administration
" on page 41, last paragraph, sentence "which could have a direct impact [on] the availability
" on page 43, 2nd to last paragraph "allows s[sic] under contract
" on page 53, middle paragraph, "Ecotope 2008 study as As[sic] a part of updating.."
" on page 59, 2nd to last paragraph, "the ramp up period is[sic] begins"
"on page 60, 3rd paragraph from the top,"the [space] residential" and also same paragraph, "the commercial sector represent[s] the[sic] Cascade's best case .." and last sentence on same page add a period
"on page 61, 1st paragraph , "the consumer is the ultimate decision marker[sic]"
"on page 62, 3rd paragraph from bottom, remove one period from the end of "to the impacts of regional legislation..[sic]"
"page 66, last paragraph, capitalize "cascade"
"page 70, 1st paragraph, add period at end of "…were developed based on 5 distinct weather areas"

Page 48, define what are U-values and R-values
Page 56, define WAP acronym

In your 2010 IRP Draft in Appendix B-2 for the slide Total therm Usage – Baker, the "medium" usage line is graphed showing more usage than the "high" usage line, is this supposed to be that way?