GTN Shipper Collaboration Meeting

San Diego

December, 2012
Update on Regulatory Filings
“Article XV provides that GTN will establish collaborative processes with interested shippers and stakeholders, including meetings at least semi-annually during the term of the Moratorium to discuss options to improve the long-term competitiveness and operation of the pipeline.”

- FERC Letter Order Approving Uncontested Settlement in RP11-2377-000
Regulatory Filings

Northbound Flow Filing
(RP 12-485 filed Mar 12/12; approved Mar 27/12)

• Changed definition of Forward Haul in Tariff from direction of flow in relation to shipper’s Primary Path to simply north-to-south flow

• Definition of Backhaul unchanged except as it relates to direction of flow on laterals

• GTN agreed to revisit the fuel issue in the event that compression becomes necessary to provide northbound service (see non-Critical Notice on Website)
Carty Lateral Certificate Application
CP12-494

- Open Season in response to Portland General Electric RFP conducted 2/13/2012 to 3/14/2012
- PGE only shipper to express interest
- 24.3 miles of 20” diameter pipe: capacity = 175,000 Dth/day
- Accompanying Mainline contract of 75,000 Dth per day from Kingsgate to Milepost 319.5 (Ione Compressor Station)
- Anticipated in-service date November 1, 2015
- Awaiting disposition of RFP process
Creditworthiness Re-write
RP12-980 filed Aug. 31/approved Sept 22

- Modified and restructured the Creditworthiness provisions of GTN Tariff
- Lower minimum debt rating from BBB to BBB- (S&P) or Baa2 to Baa3 (Moody’s)
- Increase flexibility in evaluation process by allowing inclusion of other factors in assessments
- Streamline Tariff presentation into single section; summarized in table format
- Reduces amount of credit support required for interruptible services
- Eliminates flexible credit account alternative
Regulatory Filings

Medford E-2 Rate Adjustment
RP12-1098 filed Sept 28/approved Oct 26
Negotiated Rate for WWP E-2 Service increased from $0.009363 to $0.009857 per Dth-Mile effective November 1 2012
• Deferred Account estimated to be paid off in Q1 2013

NAESB 2.0 Compliance Filing
RP13-114
• New and revised standards to support gas/electric integration, improve waste heat information
• Enhance transparency by cross-referencing tariff sections with NAESB requirements
Pressure Commitments Filing
(RP 12-15 filed Oct 11 11/12; conditionally approved Nov 6/12)

- Allows GTN to commit to maintain a minimum pressure
- Pressure commitment may require decrease in available capacity
- In these cases GTN must post a notice of the potential agreement on its website for five days
- Other shippers must have the opportunity to take the capacity without the pressure commitment
- Capacity available first-come-first-served
Reservation Charge Credits
RP12-15 filed Jan 4/12, conditionally approved Nov 6/12

Filing
• Credits: proposed “safe harbor” method to provide full credits after ten days for Force Majeure events, and on day one for non-Force Majeure
• Credits based on “confirmable nominations” within shipper’s firm MDQ
• Reservation credits are shipper’s sole remedy for failure to deliver gas
Reservation Charge Credits (continued)
RP12-15 filed Jan 4/12, conditionally approved Nov 6/12

Compliance Filing (per Commission Order)
• Removed “sole remedy” provisions
• Exemption of credits for amounts not confirmed is limited to events caused solely by the conduct of others (i.e. upstream/downstream operators)
• Definition of Force Majeure revised to clarify that outages from legislative, administrative or judicial action are only FM if the actions in question are both outside GTN control and unexpected
Questions/Discussion?
Forward-Looking Information

This presentation contains certain information that is forward looking and is subject to important risks and uncertainties. The words "anticipate", "expect", "believe", "may", "will", "should", "estimate", "project", "outlook", "forecast", "intend", "target", "plan" or other similar words are used to identify such forward-looking information. Forward-looking statements in this presentation are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management’s assessment of TransCanada's and its subsidiaries’ future plans and financial outlook. Forward-looking statements in this presentation may include, but are not limited to, statements regarding anticipated business prospects; financial performance of TransCanada and its subsidiaries and affiliates; expectations or projections about strategies and goals for growth and expansion; expected cash flows; expected costs; expected costs for projects under construction; expected schedules for planned projects (including anticipated construction and completion dates); expected regulatory processes and outcomes; expected outcomes with respect to legal proceedings, including arbitration; expected capital expenditures; expected operating and financial results; and expected impact of future commitments and contingent liabilities.

These forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. By their nature, forward-looking statements are subject to various assumptions, risks and uncertainties which could cause TransCanada's actual results and achievements to differ materially from the anticipated results or expectations expressed or implied in such statements. Key assumptions on which TransCanada's forward-looking statements are based include, but are not limited to, assumptions about inflation rates, commodity prices and capacity prices; timing of debt issuances and hedging; regulatory decisions and outcomes; arbitration decisions and outcomes; foreign exchange rates; interest rates; planned and unplanned outages and utilization of the Company’s pipeline and energy assets; asset reliability and integrity; access to capital markets; anticipated construction costs, schedules and completion dates; and acquisitions and divestitures.

The risks and uncertainties that could cause actual results or events to differ materially from current expectations include, but are not limited to the ability of TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits; the operating performance of the Company's pipeline and energy assets; the availability and price of energy commodities; amount of capacity payments and revenues from the Company's energy business; regulatory decisions and outcomes; outcomes with respect to legal proceedings, including arbitration; counterparty performance; changes in environmental and other laws and regulations; competitive factors in the pipeline and energy sectors; construction and completion of capital projects; labour, equipment and material costs; access to capital markets; interest and currency exchange rates; weather; technological developments; and economic conditions in North America.

Additional information on these and other factors is available in the reports filed by TransCanada with Canadian securities regulators and with the U.S. Securities and Exchange Commission (SEC). Readers are cautioned against placing undue reliance on forward-looking information, which is given as of the date it is expressed in this presentation or otherwise stated, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to publicly update or revise any forward-looking information in this presentation or otherwise stated, whether as a result of new information, future events or otherwise, except as required by law.
Overview

• Rates

• Regulatory Updates

• Gas prices

• North American Supply and Demand

• Western Canada Sedimentary Basin (WCSB)

• LNG Exports
2013 NGTL Interim Rates – Process/Timeline

- Oct. 16 - NGTL provided information to stakeholders about Revenue Requirement and DOH calculations (TTFP)
- Oct. 31 - Filed application and interim rates with NEB
- Nov. 20 – Reviewed detailed rates information with stakeholders (TTFP)
- Dec. 7 – NEB approved Interim Rates as filed (no complaints)

- 2013 interim rates are posted:

http://www.transcanada.com/customerexpress/2766.html
2013 NGTL Interim Rates – Key Influences

• Revenue Requirement

<table>
<thead>
<tr>
<th></th>
<th>$ billion</th>
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<tbody>
<tr>
<td>2012 Settlement Revenue Requirement</td>
<td>$ 1.31</td>
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<tr>
<td>Forecast 2011 Deferrals</td>
<td>$ 0.09</td>
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<tr>
<td>2013 Interim Revenue Requirement</td>
<td>$ 1.40</td>
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• Distance of Haul (DOH)

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<th>DOH (km)</th>
<th>2010</th>
<th>2011</th>
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</thead>
<tbody>
<tr>
<td>East Gate</td>
<td>526</td>
<td>559</td>
</tr>
<tr>
<td>West Gate</td>
<td>571</td>
<td>566</td>
</tr>
<tr>
<td>Group 2/3 Deliveries</td>
<td>298</td>
<td>341</td>
</tr>
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</table>
• **Below are the approved NGTL interim rates**
  
  - FT-D Tolls are based on a one (1) year term
  - FT-R Toll is based on three (3) year term

<table>
<thead>
<tr>
<th>CDN Cents / GJ</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empress / McNeill Borders</td>
<td>17.4</td>
<td>17.4</td>
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<tr>
<td>Alberta – BC Borders</td>
<td>18.1</td>
<td>17.7</td>
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<tr>
<td>FT-D Group 2 AB Deliveries</td>
<td>7.8</td>
<td>10.3</td>
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<tr>
<td>Average FT-R Toll</td>
<td>15.6</td>
<td>17.2</td>
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</table>
Foothills Rates

- Rates were announced Oct. 16, filed with the NEB Oct. 31.

- **Full meeting details / slides on website at this link**

- Golden Prairie M/S (60 TJ/d) 10 year contract for deliveries in Sask.

- Tariff language clean up

- Maintenance update

- **Foothills is a complaints based pipeline, one purpose of this meeting is to provide customers the opportunity to share any concerns / issues.**
• The Revenue Requirement:
  • 2013 - $54.2 Million (2012 Rate Filing: $ 65.1 Million)

• Total Firm Contract :
  • 2013 – 1,804 TJ/d (2012 Rate Filing: 1,829 TJ/d )

• Results in an FT Rate of:
• Primary challenge with Foothills BC Repairs and Maintenance is that they can only be done in the summer months due to access and environmental constraints.

• Timing can be coincidental with peak flows for summer cooling demand.
West Path Rates for 2013

NGTL  $0.177 CAD/GJ
Foothills B.C.  $0.076 CAD/GJ
GTN (K-M):  $0.354 US/Dth

Total Rate ~ $0.621 US/Dth
• Plus Fuel
• Currency conversion at Par
Mainline Restructuring Update

The Regulatory Process

- TransCanada filed application – September 2011
- Intervenor Process (written) – November to May
- Oral Hearings – June to October
- November, December – Final Argument and Reply
- NEB Decision – Q1/Q2 2013
- Implementation - TBD
October, 2011 NGTL applied to NEB to implement NEXT

May 2012, NEB approved request to suspend application, with an update to be provided Oct. 15, 2012

Numerous discussions with customers from May thru September

NGTL withdrew the application Oct. 5, 2012
Latest Comparison of Recent NYMEX Gas Price Forecasts - August 2012

Real 2010 US $/MMBtu

- Consultant 1
- Consultant 2
- Consultant 3
- Consultant 4
- Consultant 5
- TransCanada August 2012
- History
North American Demand Balance

Bcf/d

Source: TransCanada Spring 2012 Outlook
North American Supply Balance

Bcf/d

History
Forecast


Gulf of Mexico + U.S. Other
WCSB
Mexico
WCSB Unconv.
U.S. Rockies
U.S. Shale
Other

110
100
90
80
70
60
50
40
30
20
10
0
Western U.S. and Canada demand growth competes for supplies – oil sands, LNG exports and Mexico power generation influence supply competition.

Source: TransCanada Spring 2012 Outlook
Primary drivers of growth are shale, “hybrid” and tight gas plays:
- Montney
- Horn River / Cordova
- Deep Basin
- Duvernay and Liard – future potential
## WCSB Gas Supply Potential (Tcf)

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Ultimate Potential</th>
<th>Cumulative Production</th>
<th>Remaining Potential</th>
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</thead>
<tbody>
<tr>
<td>Conventional</td>
<td>280 – 370</td>
<td>175</td>
<td>105 – 195</td>
</tr>
<tr>
<td>CBM</td>
<td>40 – 60</td>
<td>0.91</td>
<td>40 – 60</td>
</tr>
<tr>
<td>Montney Hybrid</td>
<td>60 – 100</td>
<td>0.49</td>
<td>60 – 100</td>
</tr>
<tr>
<td>Horn River Shale</td>
<td>80 – 130</td>
<td>0.02</td>
<td>80 – 130</td>
</tr>
<tr>
<td>Cordova Shale</td>
<td>10 – 25</td>
<td>Negligible</td>
<td>10 – 25</td>
</tr>
<tr>
<td>WCSB Total</td>
<td>470 - 685</td>
<td>176</td>
<td>295 - 510</td>
</tr>
</tbody>
</table>

* Does not include Duvernay or Liard shale plays
Asian Investments – WCSB Natural Gas

INPEX acquisition from Nexen

STX Energy acquisition from Encana

Mitsubishi, Japanese utilities, Jogmeg, KOGAS & Penn West

Petronas & Progress

Petrochina acquisition from Shell

KOGAS & Encana

Mitsubishi & Encana

Sinopec acquisition of Daylight Energy

Toyota Tsusho acquisition from Encana

~30 billion of proposed Asian investments in the WCSB

Data from public sources
WCSB Natural Gas Supply
Base Case and Future Potential

Bcf/d

History

Forecast

Future Potential
(Duvernay, Deep Basin**, Cordova**, Liard)

Conventional*

Cordova

Horn

Montney

CBM

* Includes Tight Gas

** Expansion of Deep Basin/Cordova
Proposed North American LNG Export Projects

- Total proposed capacity of these projects by 2020 ~ 20 Bcf/d
- How much will actually get built by 2020?
- Key issues / factors
  - Commercial
  - Export licenses
  - Construction costs
  - Regulatory Approvals
  - Global competition
- B.C. export projects in-service ~2018-2020

- Shell & Partners @ Kitimat
- BC LNG
- Kitimat LNG
- Progress/Petronas
- BG
- Imperial
- Gulf Coast LNG
- Sabine Pass
- Freeport
- Lake Charles
- Cameron LNG
- Port Lavaca
- Alaska LNG
- Cove Point
- Oregon LNG
- Jordan Cove
Coastal GasLink – Shell and Partners

TransCanada’s Proposed Coastal GasLink Pipeline Project – Conceptual Route Map

Route planning will take into consideration Aboriginal, landowner and stakeholder input, the environment, archaeological and cultural values, land use compatibility, safety, constructability and economics. To minimize project footprint, TransCanada will parallel and/or use linear disturbances where practical.
Coastal GasLink - Project Timeline

Aboriginal and Community Engagement (began and continues throughout the project)

Construction

Construction launch is planned for 2015; actual date depends on regulatory and project approvals

Operation – In time to meet in-service requirements of proposed LNG Canada facility

Environmental Field Studies (begin as early as practical)

2012  •  2013  •  2014  •  2015  •  •  •  •  •  by end of decade

Project Description filed with BC Environmental Assessment Office and Canadian Environmental Assessment Agency in fall of 2012

Environmental Assessment Applications filed in early 2014
Key Observations

- There is a substantial amount of natural gas resource available across North America
- Gas prices are expected to remain below $6 US/MBtu (Real 2010$) in the longer-term with less volatility
- Not as much a question about the resource as it is about the timing and price
- Demand continues to increase driven by Gas-Fired Electricity
- North America will become a net LNG Exporter

*Natural gas is a reliable long term fuel choice – a clean, abundant resource at sustainable competitive price*
Thank You!
Leading North American Energy Infrastructure Company

One of the Largest Natural Gas Pipeline Networks
- 42,500 miles of pipeline
- Average volume is 20% of continental demand

Third Largest Natural Gas Storage Operator
- 380 Bcf of capacity

Largest Private Sector Power Generator in Canada
- 20 power plants, 10,900 MW

Premier Oil Pipeline System
- 1.4 million Bbl/d ultimate capacity

Enterprise Value ~ $55 billion

TransCanada
Fundamental Drivers in the West

- **LNG**
  - West coast
  - LNG exports

- **WCSB Supply/ Demand**
  - Supply trends, oil sands demand

- **Supply Competition**
  - WCSB versus Rockies

- **Power Generation**
  - Natural Gas, Hydro, Wind, Solar, Nuclear, Coal

- **New Infrastructure**
  - Ruby, REX

- **Exports into Mexico**
  - Gas fired power generation

- **Marcellus and Utica**
  - Impact on west to east gas flows

- **Weather**

- **Storage Levels**
USPL Transactional Systems Update
Summary

- Each U.S. Pipeline Has a Unique Transactional System
  - Transactional System Functionality

- Next Step of Consolidation in Houston is System Consolidation

- Transactional System Consolidation Benefits are Substantial
  - Regulatory Compliance Cost and Penalty Risk Mitigation
  - Eliminate System Obsolescence and Breakage Risk
  - Develop a Platform That Facilitates Future Expansion

- Project cost – approx $25-$30 million, 3.5 Years
  - Results in a single, expandable, modern system
Project Benefits

- **Regulatory Compliance Risk Mitigation**
  - Reduce the risk of non-compliance penalties by automating processes and controls
    - Increasing FERC scrutiny – ANR, NB, GLGT, GTN have all been audited in the last 2 years
    - NAESB changes occur annually and affect all pipes

- **Eliminate System Obsolescence Risk**
  - Reduce the business risk from breakage of obsolete systems
  - Existing systems are up to 15 years old, with unsupported vendor infrastructure and code

- **Develop a Platform That Facilitates Future Expansion**
  - The value of an acquisition or green field development is enhanced by an easily accommodating transactional platform
The Majority of Business Benefits Are Achieved Through Phase 1
Marketing Update
Dec 12, 2012
Marketing Update

Capacity and Pricing Philosophy

• Financial forwards do NOT typically capture the full value of the actual spread

• Flow volatility on GTN primarily at Malin, lower at Stanfield

• Offer limited capacity at a discount for certain markets with DF, Seasonal or Annual capacity packages

• Incremental Malin capacity will be based on value at AECO/OPAL and our view of market fundamentals

• GTN considers Stanfield and certain other locations as premium markets based on supply alternatives

• Discounts will only apply to specific path, flexibility will be incrementally negotiated
What are we watching?

- California storage levels
- Canadian storage levels – WCSB & Eastern Canada
- Hydro levels (California, Pac NW)
- NA production (WCSB, Rockies, Big Shales)
- Weather forecasts
- Electric generation outages (eg nuclear)
- Pipeline maintenance or outages
AECO – Malin Gross Spread (Forwards)

Liquid uplift in Alberta...it can make the difference
Winter 2013 - FC Netbacks to WCSB

- Netforwards: Ruby has 7¢ advantage over GTN
- Netbacks: GTN has 11¢ while Ruby has 12-24¢ over next best alternative

WCSB Netbacks (FC)

- TCPL (Dawn) vs AECO W 2013 Forward Price of $3.29
- GLGT (SH - West)
- Viking (Chicago)
- GLGT (Dawn)
- GTN (Malin)
- TCPL (Iroquois)
- PNGTS

Opal Netbacks (VC)

- Dom S
- Cheyenne
- Malin vs Opal W12/13 Forward Price of $3.55
- SoCal

Netforwards (VC): Malin, PG&E South

- GTN vs PG&E South W12/13 Forward Price of $3.70
- Ruby vs Malin W12/13 Forward Price of $3.62
- Topock (EP)
- Topock (TW)

Forward Market Data as of December 3, 2012
Note: Removed Liquids uplift, new Foothills tolls Eff. Jan’13 & full cost on Canadian pipelines
Summer 2013 - FC Netbacks to WCSB

- **Netforwards:** Ruby has 5¢ advantage over GTN
- **Netbacks:** GTN has 16¢ while Ruby has 14-18¢ over next best alternative

### WCSB Netbacks (FC)

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Netbacks (FC)</th>
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<tbody>
<tr>
<td>PNGTS</td>
<td>$0.086</td>
</tr>
<tr>
<td>TCPL (Iroquois)</td>
<td>$1.889</td>
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<tr>
<td>TCPL (Dawn)</td>
<td>$2.022</td>
</tr>
<tr>
<td>GLGT (SH - West)</td>
<td>$2.425</td>
</tr>
<tr>
<td>Viking (Chicago)</td>
<td>$2.620</td>
</tr>
<tr>
<td>GLGT (SH - Central)</td>
<td>$2.623</td>
</tr>
<tr>
<td>GLGT (Dawn)</td>
<td>$2.782</td>
</tr>
<tr>
<td>GTN (Malin)</td>
<td>$2.938</td>
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</table>

**vs AECO W 2013 Forward Price of $3.29**

### Opal Netbacks (VC)

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Netbacks (VC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dom S</td>
<td>$3.43</td>
</tr>
<tr>
<td>Cheyenne</td>
<td>$3.47</td>
</tr>
<tr>
<td>Malin</td>
<td>$3.61</td>
</tr>
<tr>
<td>SoCal</td>
<td>$3.74</td>
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**vs Opal Summer 2013 Forward Price of $3.58**

### Netforwards (VC): Malin, PG&E South

<table>
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<tr>
<th>Pipeline</th>
<th>Netforwards (VC)</th>
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<tbody>
<tr>
<td>GTN</td>
<td>$3.67</td>
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<td>Topock (EP)</td>
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<tr>
<td>Topock (TW)</td>
<td>$3.65</td>
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<tr>
<td>Ruby</td>
<td>$3.62</td>
</tr>
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</table>

**vs PG&E South Summer 2013 Forward Price of $3.82**

**vs Malin Summer 2013 Forward Price of $3.65**

*Forward Market Data as of December 3, 2012*

Note: Removed Liquids uplift, new Foothills tolls Eff. Jan’13 & full cost on Canadian pipelines
Summary

• Challenging forward financials near term
• Supply impact - Winter in Alberta vs Rockies, east vs west
• It’s looked like this before...and then it changes
• We are open for business...talk to your marketing rep

Questions? Comments?
Assessment of Mexico Power Demand Growth on Southwest U.S.

December 13, 2012
CFE North-Northwest Pipeline System

<table>
<thead>
<tr>
<th>Project</th>
<th>Power Plant</th>
<th>Date</th>
<th>Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Norte II</td>
<td>2013</td>
<td>459</td>
</tr>
<tr>
<td>2</td>
<td>Pto. Libertad (Conv)</td>
<td>2014</td>
<td>632</td>
</tr>
<tr>
<td>3</td>
<td>Encino (Norte III)</td>
<td>2015</td>
<td>459</td>
</tr>
<tr>
<td>4</td>
<td>Topolobampo II</td>
<td>2016</td>
<td>700</td>
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<tr>
<td>5</td>
<td>Topolobampo III</td>
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<td>700</td>
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<td>6</td>
<td>Guaymas II</td>
<td>2017</td>
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7,500 MW
CFE Natural Gas Power Plant Development Plans

<table>
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<th>Capacity (MW)</th>
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<td>Salamanca Fase I</td>
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<td>2</td>
<td>Centro</td>
<td>2013</td>
<td>640</td>
</tr>
<tr>
<td>3</td>
<td>Centro II</td>
<td>2015</td>
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<td>4</td>
<td>Valle de Mexico II</td>
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<td>601</td>
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<td>5</td>
<td>Aguascalientes</td>
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<td>6</td>
<td>Manzanillo II U1</td>
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<td>460</td>
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<td>Valle de Mexico III</td>
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<td>8</td>
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<td>Salamanca</td>
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<td>Jorge Luque</td>
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<td>11</td>
<td>Guadalajara I</td>
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<td>12</td>
<td>Central (Tula)</td>
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<tr>
<td>16</td>
<td>San Luis Potosi</td>
<td>2025</td>
<td>940</td>
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10,000 MW
Southwestern U.S. Supply and Transportation Assessment for CFE

- What is the impact of Mexico power demand growth on the Southwest U.S. market?
- CFE plans for gas fired in Northwest and South Central Mexico

### CFE Future Project

<table>
<thead>
<tr>
<th>NorthWest Plans</th>
<th>In-service</th>
<th>Length (Km)</th>
<th>Capacity (Mmcfd)</th>
<th>Capital ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1  Sasabe to Guaymas</td>
<td>Sep-2014</td>
<td>545</td>
<td>750</td>
<td>$1500</td>
</tr>
<tr>
<td>2  Guaymas to Topolobampo</td>
<td>Jul-2016</td>
<td>345</td>
<td>500</td>
<td>$880</td>
</tr>
<tr>
<td>3  El Encino to Jimenez and Topolobampo</td>
<td>Mar-2016</td>
<td>720</td>
<td>450</td>
<td>$1700</td>
</tr>
<tr>
<td>4  Topolobampo to Mazatlan</td>
<td>Jul-2016</td>
<td>320</td>
<td>200</td>
<td>$800</td>
</tr>
</tbody>
</table>
Mexico Natural Gas Infrastructure

Map showing locations such as North Baja, Guadalajara, Topolobampo, Mazatlan, Juarez, Monterrey, Altamira, Mexico City, Cancun, Valladolid, and others, with lines indicating natural gas pipelines. The map includes TransCanada Natural Gas Pipelines, Third Party Natural Gas Pipelines, and LNG Import Facilities.
Southwestern U.S. Supply and Transportation Assessment for CFE

- What is the impact of Mexico power demand growth on the Southwest U.S. market?
- CFE plans for gas fired in Northwest, North Central, and South Central Mexico

Source: Fall 2012 TSO (Preliminary)
Southwestern U.S. Supply and Infrastructure Review

Supply Purchase Options: Purchased at the border or reach back to liquid market or supply hubs with firm transportation on U.S. pipelines
Pipeline Deliveries into U.S. Southwest
Recent Flow History

Significant unutilized capacity exists on EP North, but S. Mainline is nearly full, as well as existing cross-overs. So, New capacity needed to access this supply long-term

Limited unutilized capacity – expansions or new builds needed long term to access supply
Impact of Increased Northwest Mexico Demand Price Basis to Henry Hub

Key Assumptions
- **Base Case**: RBAC 2012Q1 with no incremental power demand (solid black line)
- **Demand ramp up profile**: +0.35 Bcfd in 2015, +0.50 Bcfd in 2016, +0.65 Bcfd in 2017

**Note**: Sufficient cross-border infrastructure expansions were included to serve incremental load but no mainline expansions on El Paso were assumed
Southwestern U.S. Supply – Impacts

- Demand growth in northwestern Mexico will strain segments of El Paso Natural Gas
  - Expansions likely
  - Capacity in key paths is heavily utilized and contracted

- Southwestern US market centers have higher volatility and price than supply hubs
  - Transportation costs from supply areas and pipeline capacity constraints lead to higher prices and volatility
  - Higher demand due to Mexico growth likely to exacerbate this condition

- Transportation contracts back to liquid hubs such as Waha and San Juan are advisable
  - Firm transportation contract needed to ensure reliability
  - Obtain Right of First Refusal (ROFR)
  - Sign as short a term as practical to keep options open on other routes
Update on Northbound Service Offerings
“Article XV provides that GTN will establish collaborative processes with interested shippers and stakeholders, including meetings at least semi-annually during the term of the Moratorium to discuss options to improve the long-term competitiveness and operation of the pipeline.”

- FERC Letter Order Approving Uncontested Settlement in RP11-2377-000
Northbound Service

History

- Service request from Ruby Pipelines LLC received in late 2011 for Firm Northbound Service from Turquoise Flats to Stanfield
- GTN determined that service could be provided with minor enhancements to measurement and control systems
- Contract finalized with Ruby: 10,000 Dth/day FTS-1 Service Agreement from Turquoise Flats to Stanfield @ Max Rate (~ $0.21); no fuel initially
- Contract now in Service: Term Nov. 1/2012 to Mar. 31/2018
Available Northbound Services

- Previously existing capacity now available for Firm Northbound service
- GTN website lists 95,000 Dth Unsubscribed Firm Capacity available from Turquoise Flats to Stanfield
- Firm Northbound Capacity not available from Malin: TF≠Malin
- Shippers can not acquire TF-Stan Firm capacity and flow Stan to Malin on secondary basis
- Secondary Backhaul service still available
- Shippers with Firm Forward haul contracts with Malin as the Primary Delivery Point can flow secondary Malin–Stan or TF-Stan
Northbound Service

Available Northbound Services

*Change of Receipt Point*

- **Existing Shippers may change Primary Receipt Point if operationally feasible**
- **King – Stan shipper changes receipt point to TF:** path becomes TF – Stanfield
- **Must pay additional mileage-based demand charges if applicable**
- **K-S Reservation ~ $0.1775; TF-S Reservation ~ $0.205**
Available Northbound Services

Change of Delivery Point

• Existing shippers may change Primary Delivery Point if operationally feasible
• King-Stan shipper changes to King – Malin
• Must pay additional mileage – based demand charges
• Shipper may flow Malin to any point north on a secondary basis
• Secondary backhaul service reliability is enhanced by Firm Northbound capability
• Shipper may return to his original Receipt/Delivery point configuration if operationally feasible
Northbound Service

Questions/Discussion?
Thank You.