Federal Energy Regulatory Commission
Natural Gas Markets Conference PL02-9-000
October 25, 2002

Session I – Supply and Demand – Anticipated long term growth issues
Panel B

Comments of Calpine Corporation

I. Calpine Introduction
   a. Independent power producer with appox. 17,8000 MW of gas fired in operation, 9,700 MW in construction
   b. Estimated gas usage of 3 Bcf per day

II. Physical Supply/Demand versus Economic/Financial
   a. Calpine expects physical demand for gas (driven by power demand) to increase and it will be met with new production and LNG imports
   b. The complexion of the market has changed significantly
      i. Fewer participants (Enron, Dynegy, Aquila)
      ii. Scaled back activity (Williams, El Paso)
      iii. Credit erosion on all fronts PG&E, CMS, Calpine, Mirant, Reliant, Duke
   c. Result has been a concentration of sellers (and buyers), reduction of liquidity, increase in market and price risk, and increase in market power by the few suppliers remaining
      i. Marketers (the guys you love to hate) traditionally played a middleman role and provided supply and services including gas management, financial (risk management) services and credit support as well as provided a marketplace with numerous competitive market participants. This increased price discovery/transparency resulting in a more competitive environment.
      ii. As a result of credit and liquidity issues & fewer market participants there is an increase in risks for both suppliers and customers. This is from a decrease in the diversified portfolio of on the part of both parties.
   d. There may well be an extended gap in the physical supply/demand because of the economic/financial supply/demand
      i. Power companies driving gas demand
      ii. Lack of credit capacity to acquire existing capacity or fund infrastructure development
      iii. Lack of credit capacity to enter into long-term supply arrangements to underpin production

III. What can the Commission Do?

a. Calpine does not want to infer that the Commission should interfere with the market but it should be careful not to exacerbate the situation
b. Do not allow "economic gold plating" by pipelines in regards to credit
    i. Credit provisions should be fair to both pipelines and shippers
    ii. Credit evaluation process should be transparent
    iii. Credit provisions should not be an economic barrier to the pipeline grid
    iv. Credit evaluation should be applied equally to all customers and affiliates
    v. Credit evaluation should extend beyond the macro level of the corporate rating agencies
    vi. Credit provisions must consider a pipeline's duty to mitigate potential damages
    vii. Credit evaluation should be based on actual risk (construction example)
    viii. Credit provisions and the attendant risk should be considered in a pipelines allowed rate of return
    ix. Customers should be able to request and receive a updated credit evaluation based on changed circumstances (timeline)

IV. Conclusion

The Commission should not allow monopoly pipelines to make a "run on the bank" through over collateralization of credit risk, especially during this industry low point caused by the economic downturn, regulatory uncertainty and energy market unrest. Pipeline's attempts to financially gold plate their system should be rebuffed and the Commission should review and establish industry guidelines and policies for credit evaluations and credit provisions on an industry wide, not a piece meal basis. If credit evaluations and provisions are not based on the actual risks faced by the pipeline with consideration of their duty to mitigate any potential damage, then hundreds of millions of capital dollars will be unnecessarily and uneconomically withheld from the market. These dollars will not be available to the industry for investment in energy infrastructure in order for supply to meet demand and will only contribute to a credit death spiral and energy price volatility.

Natural Gas Markets Conference
Session III – Offshore Gathering Policy
October 25, 2002
Docket No. PL02-9-000

Comments of Shell Gas Transmission
As presented by David Halphen

Good morning and thank you for the opportunity to speak here today. My name is David Halphen and I am a Vice President of Shell Gas Transmission with responsibilities that include regulatory affairs. Shell Gas Transmission is an owner and operator of over 1,200 miles of offshore gathering and jurisdictional pipelines and a company that continues to invest in new infrastructure to serve frontier developments in the Gulf of Mexico with over 300 miles of pipeline currently under construction.

One stated objective of this session is to focus on whether the commission's current policies and definitions of gathering and transmission, as they apply to offshore facilities, help or hinder the development of offshore supply sources. It is our position that the single most important thing the Commission can do is to provide as much clarity, certainty and predictability as possible when it comes to supply infrastructure development in the Gulf of Mexico.

While the existing offshore policy statement, with its presumption that pipelines built to serve production from water depths of 200 meters and deeper are gathering, may not be perfectly clear, the text is clear enough to allow needed new deepwater infrastructure to be built in a timely fashion.

The Commission should not allow the specific concerns and issues related to the spin-down of regulated facilities to cloud the picture for new infrastructure development. Deepwater projects are complex beasts that require years of pre-development planning and engineering. The offshore supply industry must have a clear indication as to the regulatory requirements that we face in order to meet the increasing energy needs of America.

When it comes to enacting new standards and requirements meant to enhance the delivery of natural gas, the Commission must recognize that not all regulated pipelines are created equal and as such, there is a legitimate need to modify the applicability of regulations with regard to pipelines that operate in different environments. This falls under the category of "one-size-does-not-fit-all". For example, a new standard or requirement designed to meet the needs of market area shippers or end-users is potentially meaningless to an offshore supply area system. It is expensive and time consuming to constantly upgrade software and processes and it is frustrating to implement new requirements that are not utilized by our customers.

I offer three operational realities that distinguish the operations of an offshore system from that of a long-line or on-shore system.

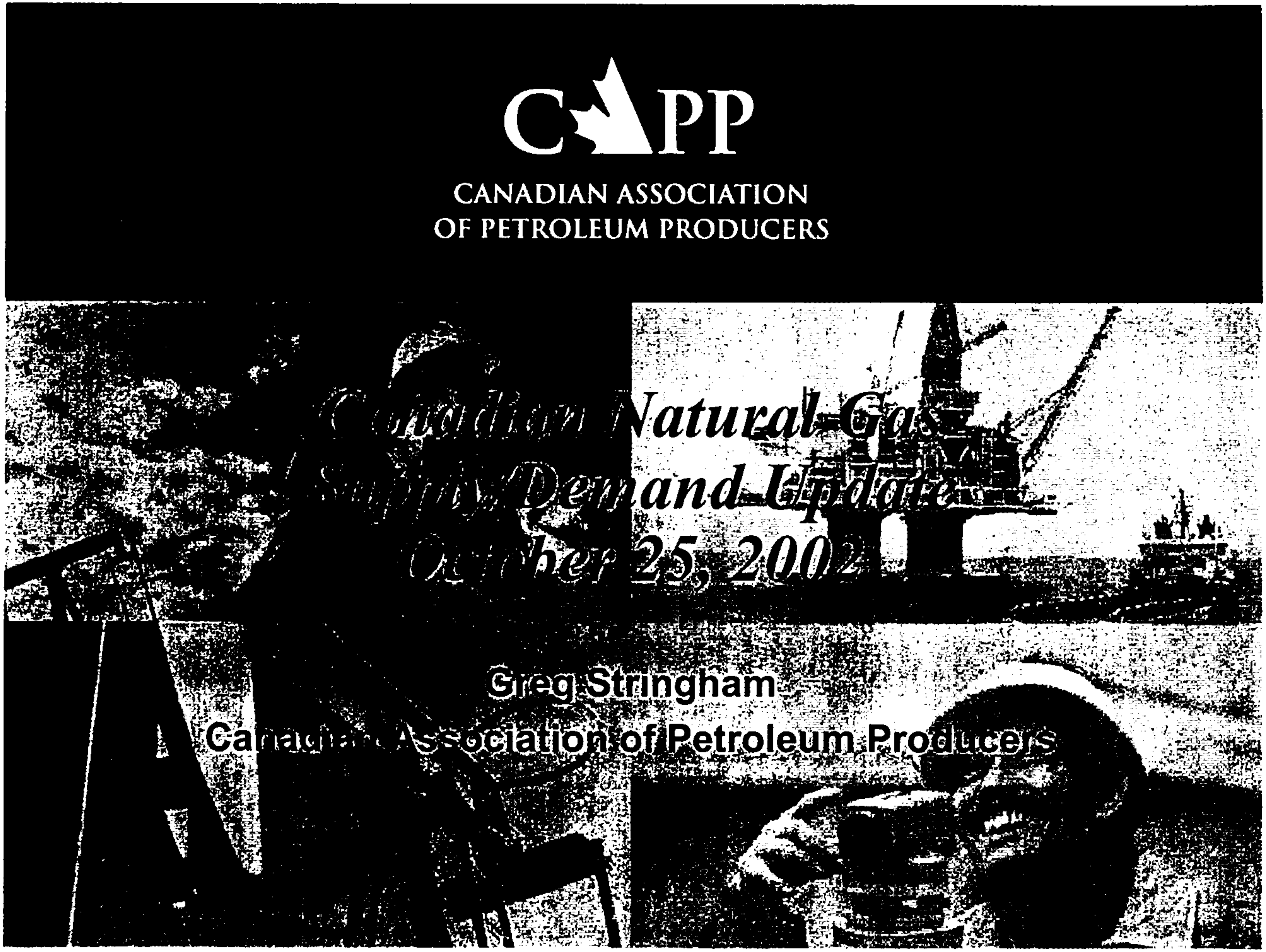
First – Offshore pipelines primarily transport gas from production areas to pipelines that serve downstream markets. Volumes and day-to-day demand for service on offshore systems generally fluctuate only with geologic conditions or changes in production from individual wells. Onshore systems see volume changes that are often driven by degree-day variations or changing storage injection or withdrawal patterns. Further, offshore tariffs are often designed with the unique needs of the producer in mind. The FT-2, flexible firm service, which matches capacity with a producers changing production profile, is an example of this uniqueness. In the short term, market conditions impact supply and demand on onshore systems while it is mostly mechanical and operational conditions that affect volumes on offshore systems.

Second – Offshore gas production often contains high volumes of liquids and retrograde condensate that pose operational issues and require a close alignment with processing and production functions. This is a safety and operational integrity and reliability issue for offshore operators.

The third operational reality that distinguishes offshore systems involves monitoring of operating pressure requirements necessary to prevent well shut-ins and problems at downstream processing plants. The high volumes from individual wells and on individual systems coupled with tremendous changes in water depths and temperatures create an operating environment not experienced by onshore pipelines. Continuous and direct communication between all offshore stakeholders (that is producers, platform operators, pipelines and processing plants) is necessary to insure the safe, efficient delivery of natural gas.

In conclusion, the Commission has asked what can be done to help the development of offshore supply sources. Shell Gas Transmission suggests that the Commission maintain regulatory stability by keeping the existing tests of what constitutes gathering and jurisdictional transmission in the offshore with respect to new facilities and that the Commission recognizes that real problems and issues are created when a "one-size-fits-all" solution is mandated for pipelines.

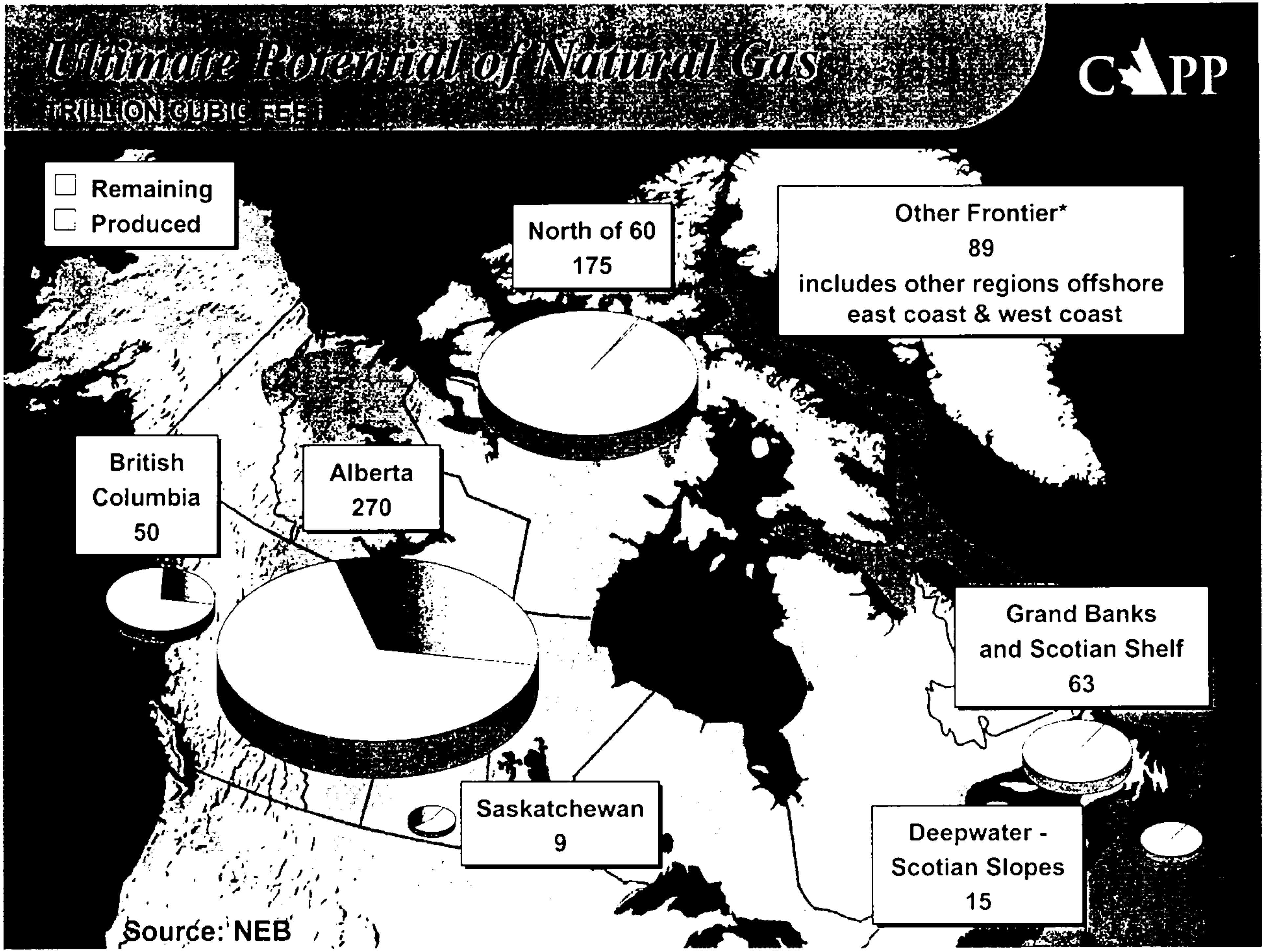
Do not distract us with new or changing regulatory mandates. Allow us to focus on the task at hand in the offshore, which is the efficient and safe operation of existing facilities and the development and implementation of new technologies that meet the needs of new deepwater developments.


CAPP
CANADIAN ASSOCIATION
OF PETROLEUM PRODUCERS
Canadian Natural Gas
Supply/Demand Update
October 25, 2002
Greg Stringham
Canadian Association of Petroleum Producers

Canadian Exports to the U.S. in 2001

CAPP

- Exports to US: 3.7 trillion cubic feet per year
- Largest exporter of natural gas to the US
- Canada makes up 94% of total US gas imports
- Canada supplies 17% of US gas consumption


Ultimate Potential of Natural Gas
TRILLION CUBIC FEET
CAPP
Remaining
Produced
North of 60
175
Other Frontier*
89
includes other regions offshore
east coast & west coast
British
Columbia
50
Alberta
270
Grand Banks
and Scotian Shelf
63
Saskatchewan
9
Deepwater -
Scotian Slopes
15
Source: NEB

High

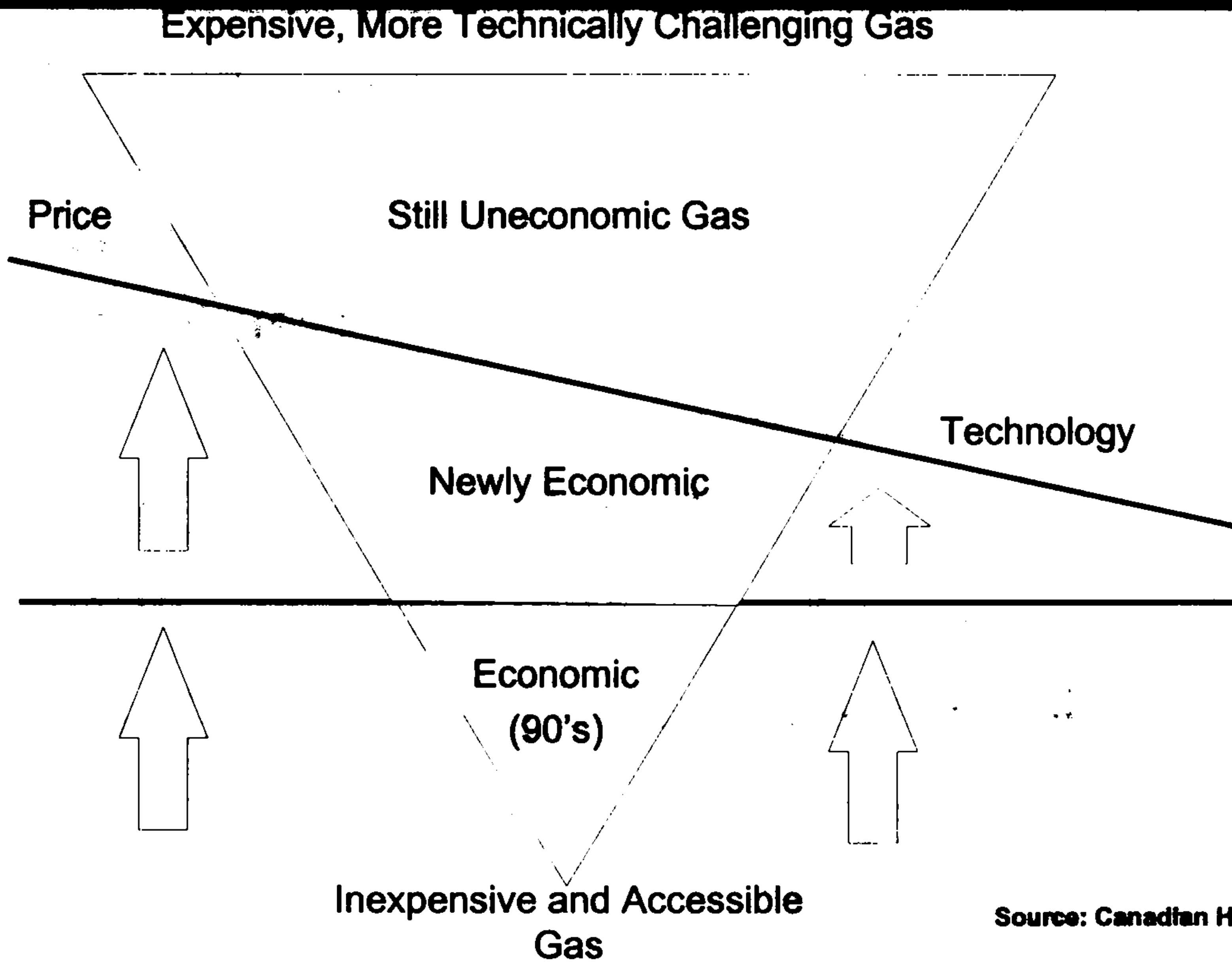
Level of Development

Low

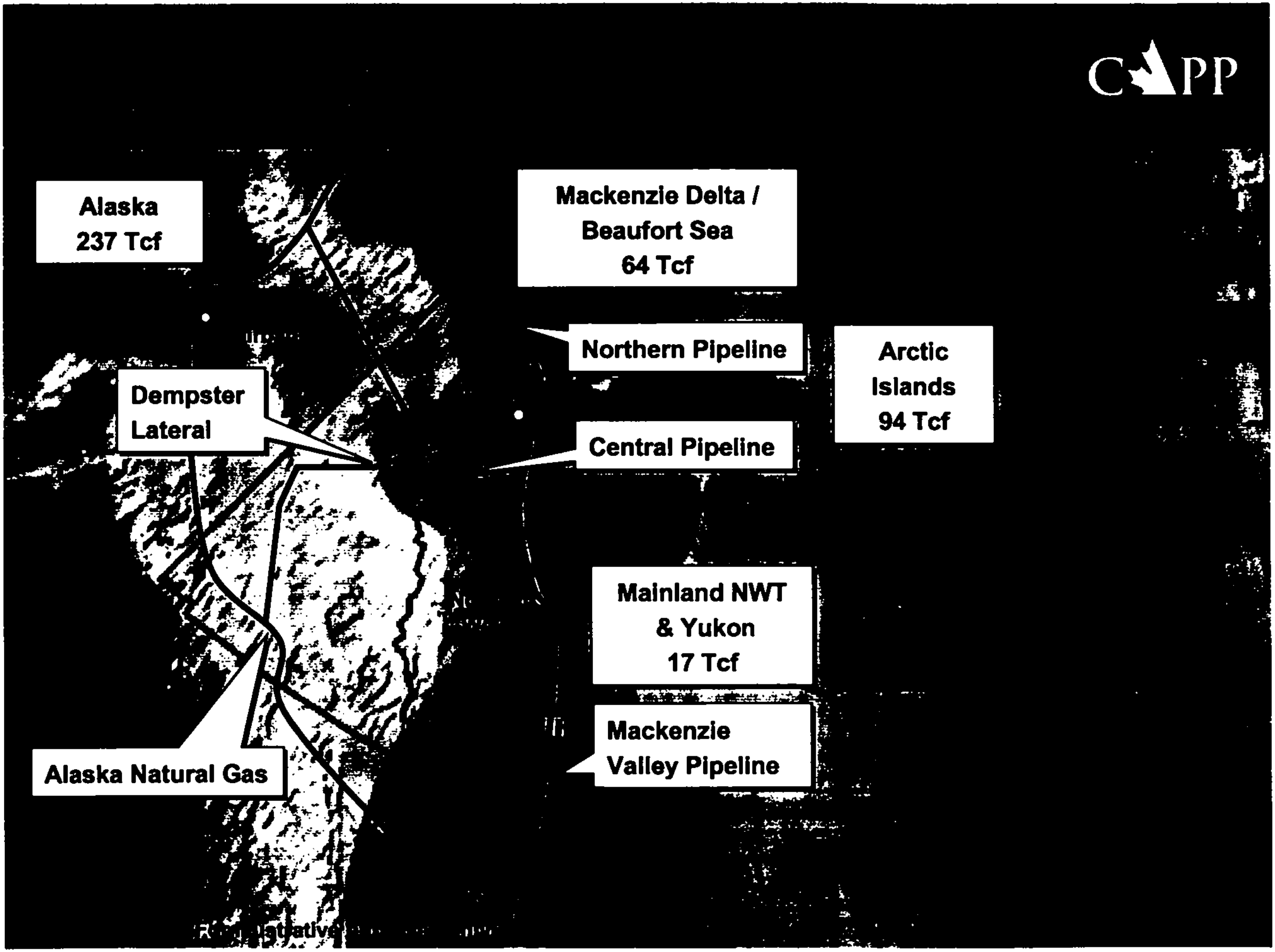
	Maximum	Minimum
WCSB Conventional (NEB)	209	138
Atlantic Canada (NEB & CNSOPB)	59	33
Mackenzie Delta (NEB)	64	64
Coalbed Methane (GSC)	130	0
Total	462	235

CAPP

- Significant untapped potential remaining
- Demand - expected moderate growth
- Sufficient pipeline capacity - for now
- Technology - seismic, drilling, etc.
- New supplies:
  - Northern gas
  - Atlantic Canada offshore
  - Coal-bed methane

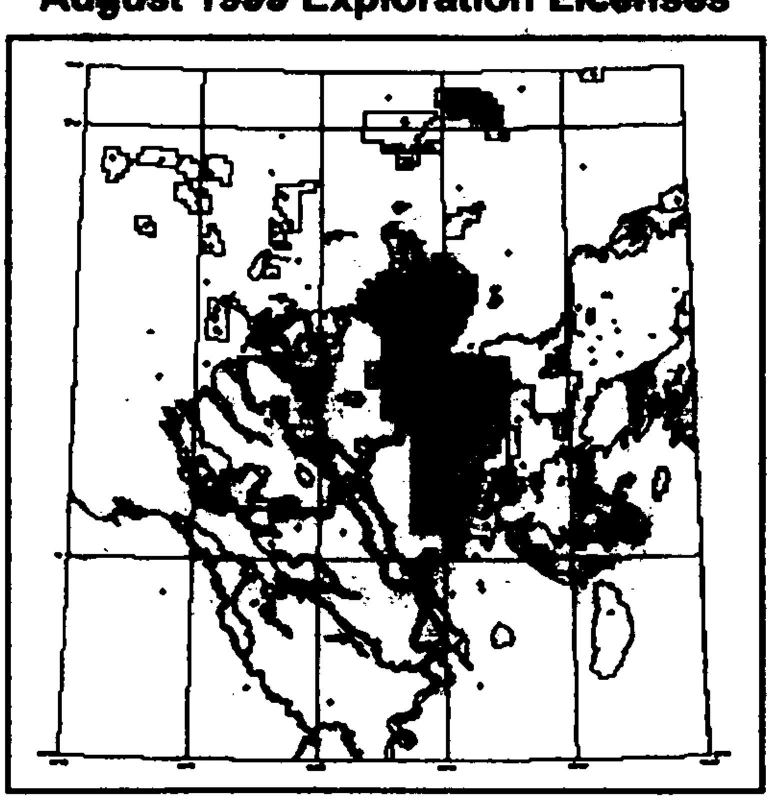


Source: Canadian Hunter

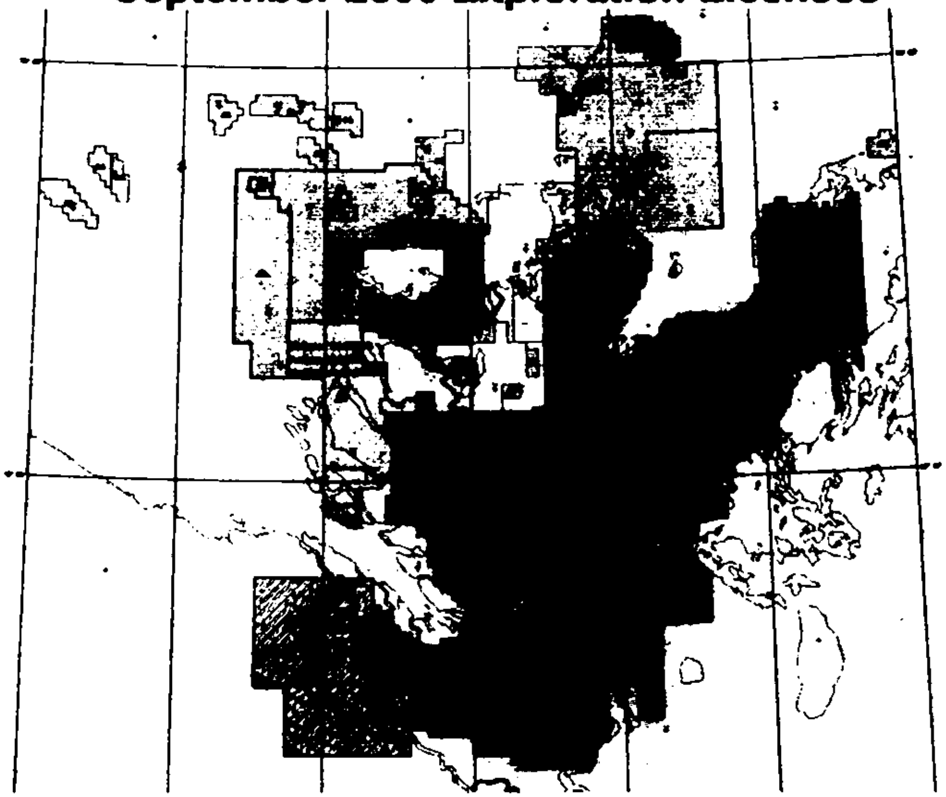

CAPP
Alaska
237 Tcf
Mackenzie Delta /
Beaufort Sea
64 Tcf
Northern Pipeline
Arctic
Islands
94 Tcf
Dempster
Lateral
Central Pipeline
Mainland NWT
& Yukon
17 Tcf
Mackenzie
Valley Pipeline
Alaska Natural Gas

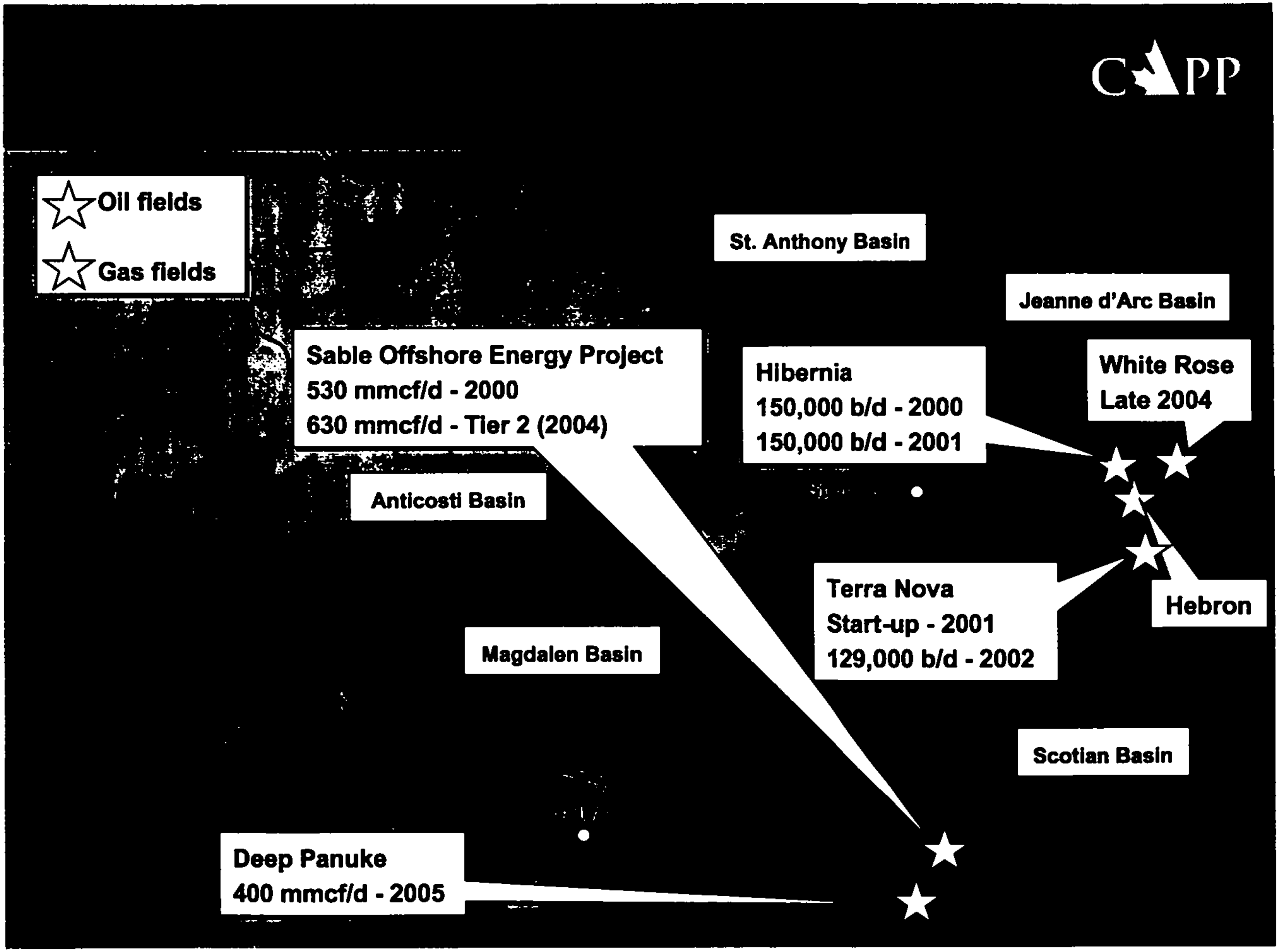
- Total industry exploration expenditures to exceed $C 800 million
- Number of players in region has increased significantly

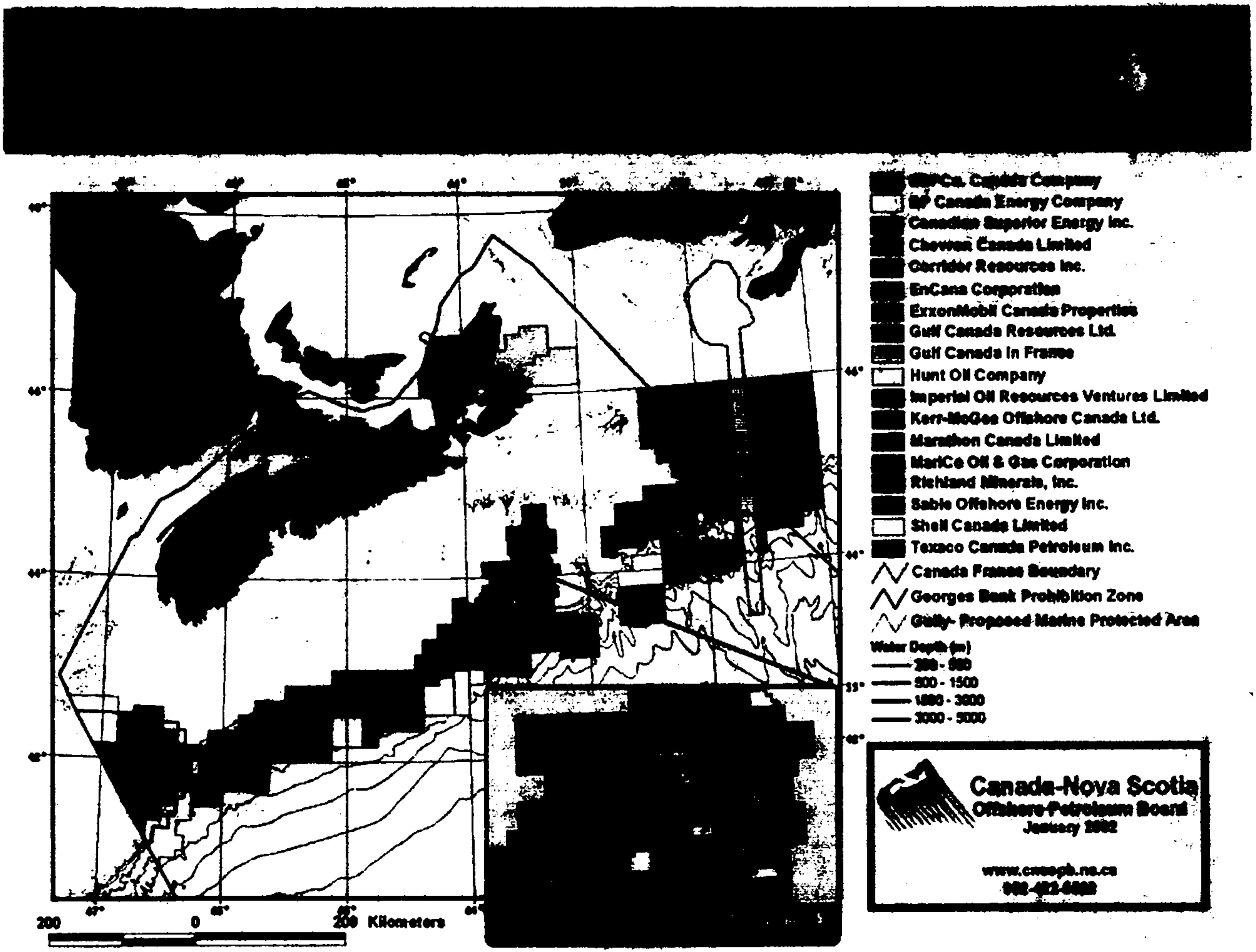
August 1999 Exploration Licenses



September 2000 Exploration Licenses



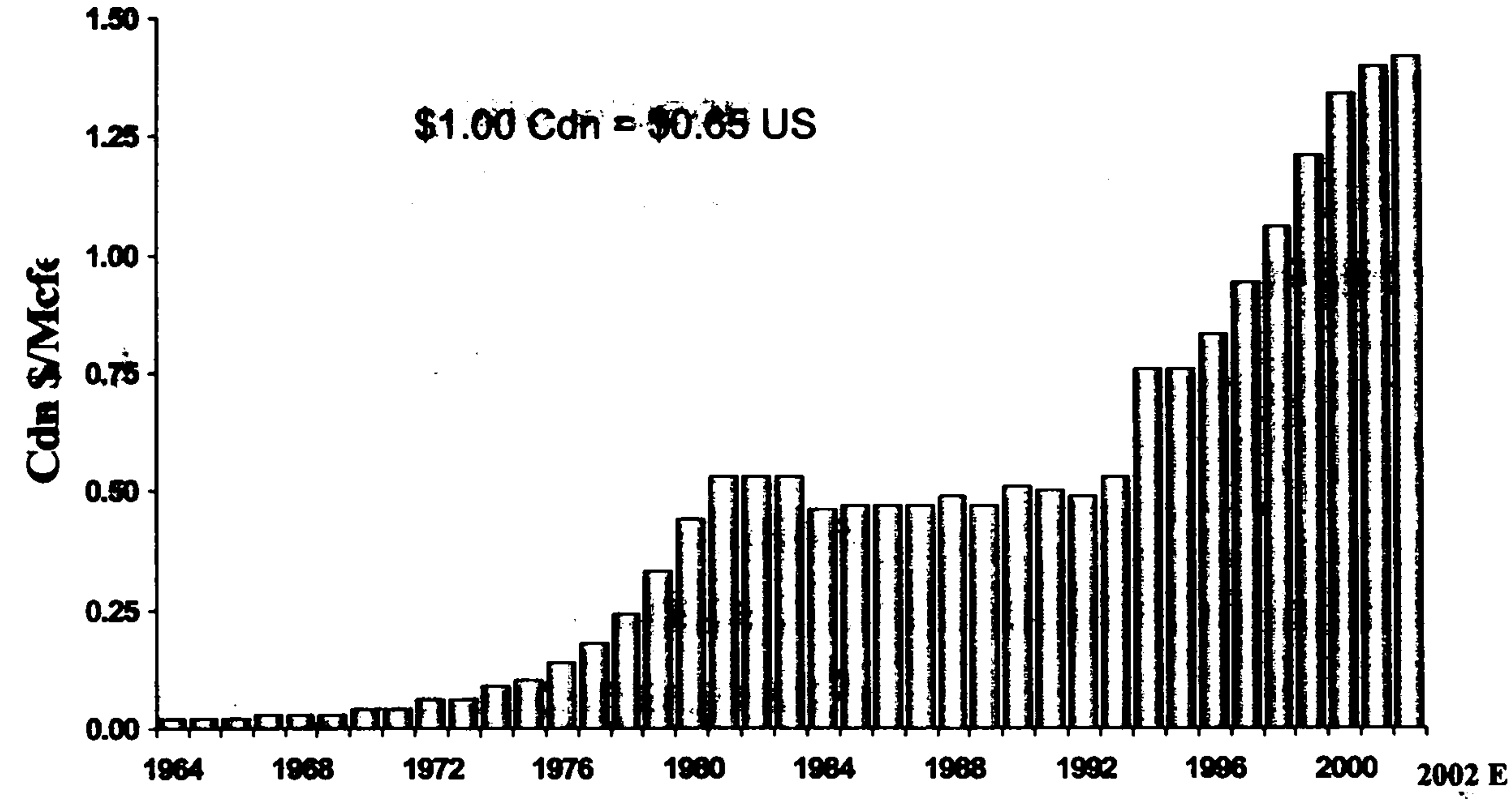

CAPP
Oil fields
Gas fields
St. Anthony Basin
Jeanne d'Arc Basin
Sable Offshore Energy Project
530 mmcf/d - 2000
630 mmcf/d - Tier 2 (2004)
Hibernia
150,000 b/d - 2000
150,000 b/d - 2001
White Rose
Late 2004
Anticosti Basin
Terra Nova
Start-up - 2001
129,000 b/d - 2002
Hebron
Magdalen Basin
Scotian Basin
Deep Panuke
400 mmcf/d - 2005


BP Canada Energy Company
Canadian Superior Energy Inc.
Chevron Canada Limited
Corridor Resources Inc.
EnCana Corporation
ExxonMobil Canada Properties
Gulf Canada Resources Ltd.
Gulf Canada In Frame
Hunt Oil Company
Imperial Oil Resources Ventures Limited
Kerr-McGee Offshore Canada Ltd.
Marathon Canada Limited
MarCo Oil & Gas Corporation
Richland Minerals, Inc.
Sable Offshore Energy Inc.
Shell Canada Limited
Texaco Canada Petroleum Inc.
Canada France Boundary
Georges Bank Prohibition Zone
Gully- Proposed Marine Protected Area
Water Depth (m)
500 - 1500
3000 - 5000
Canada-Nova Scotia
Offshore Petroleum Board
January 2002
200
0
200 Kilometers

CAPP

- **Needs Time and Certainty**
  - **Access to the resource**
  - **Timely approval processes**

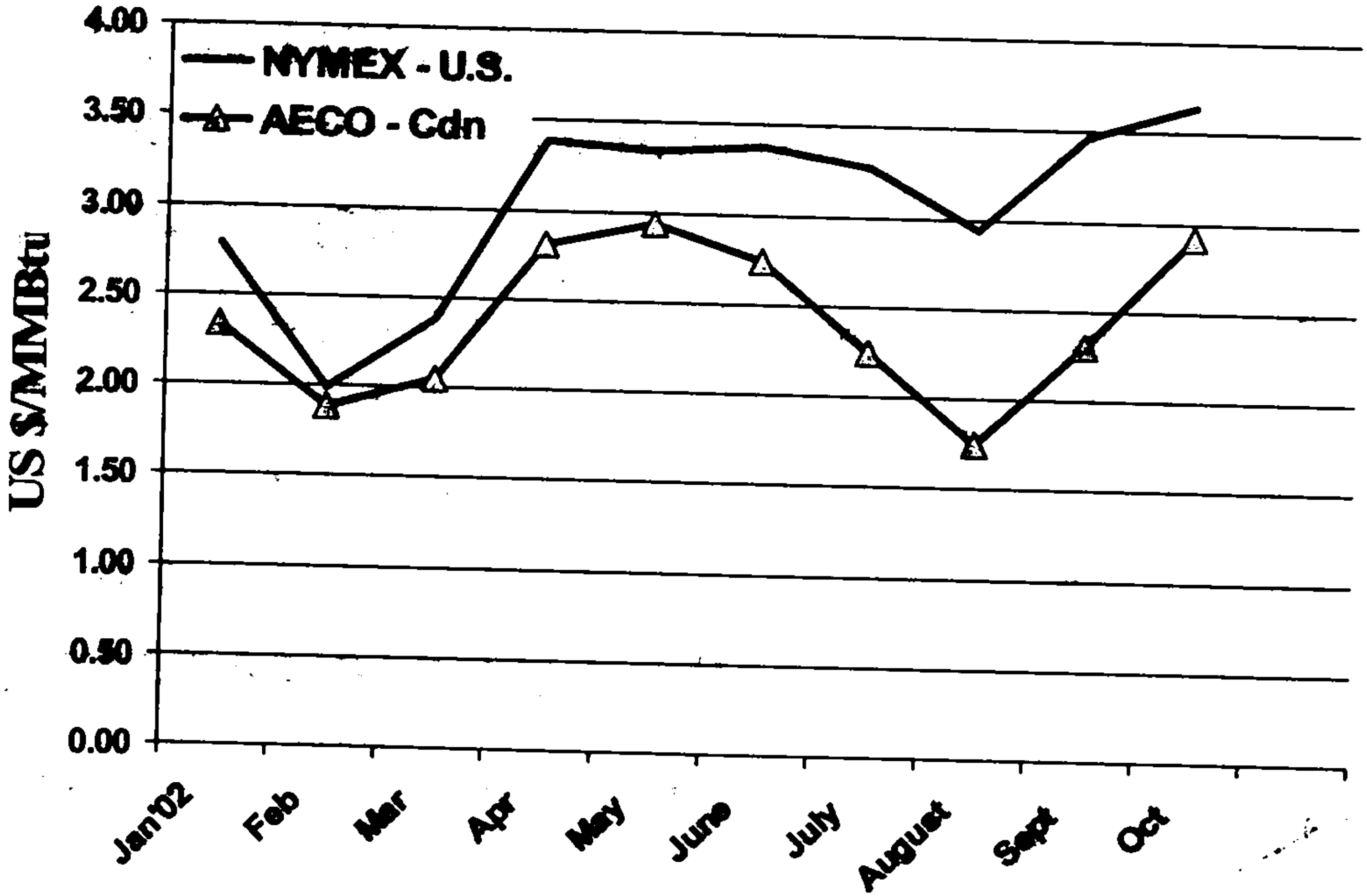
- **Depends on Costs**
  - **Rising costs - tax, F&D, land, power, transportation**
  - **Move to deeper and more remote areas**
  - **Shorter drilling season**



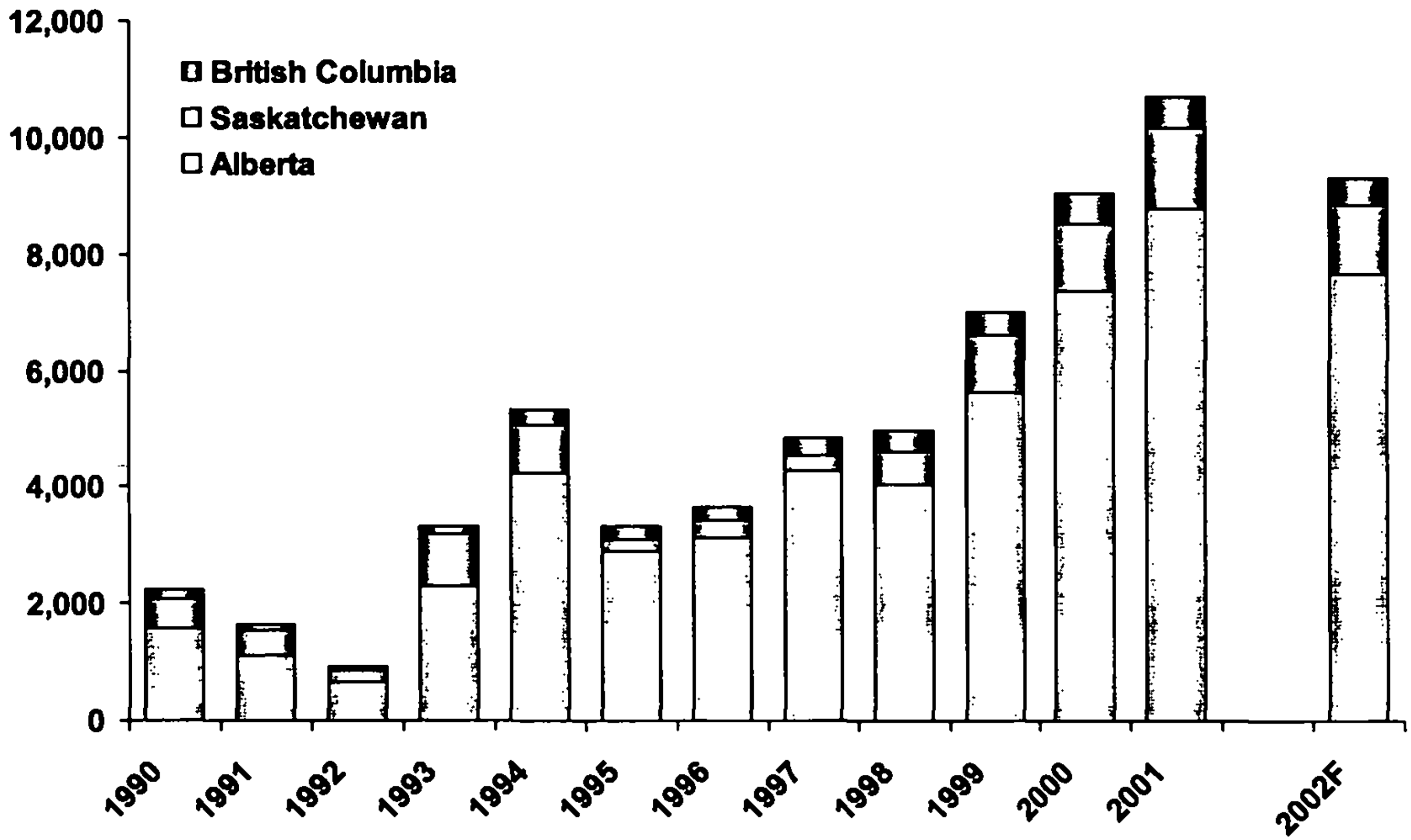
Source: ARC Financial - 10year rolling average
Note: Includes natural gas liquids converted at 10 bbl: 1 Mcfe

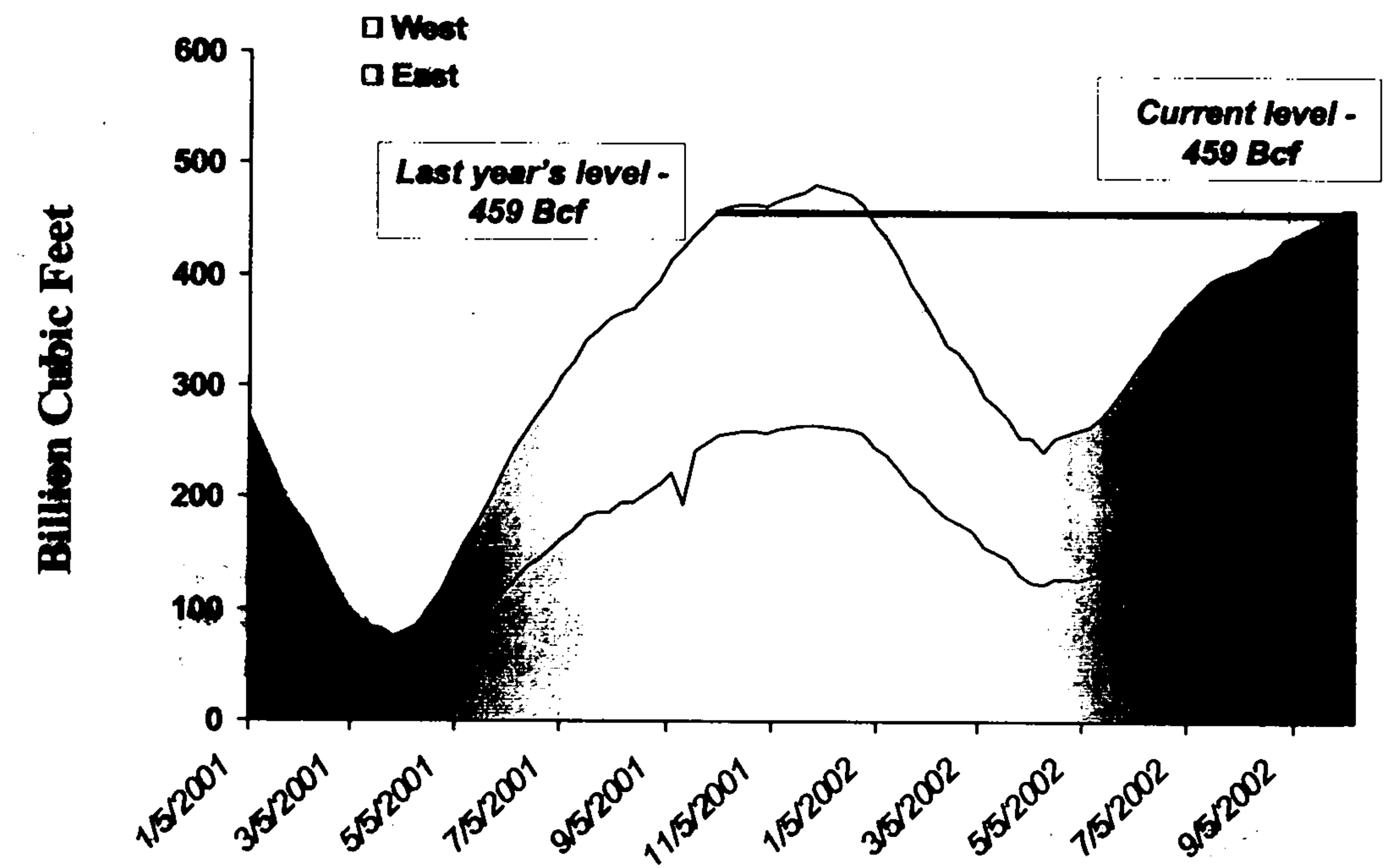
CAPP

- Industry Restructuring
  - after record M&A year - rationalizing drilling plans
  - Royalty trusts distributing potential drilling capital
- Canadian storage full earlier this year
  - but quickly coming in line with 5 year average
- Northern Gas
  - Mackenzie Delta regulatory filing anticipated 2003
- Coal bed methane
  - development just starting in Canada
- Atlantic Canada - Nova Scotia gas
  - CNSOPB added new deep water resources


4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
US $/MMBtu
NYMEX - U.S.
AECO - Cdn
Jan'02
Feb
Mar
Apr
May
June
July
August
Sept
Oct

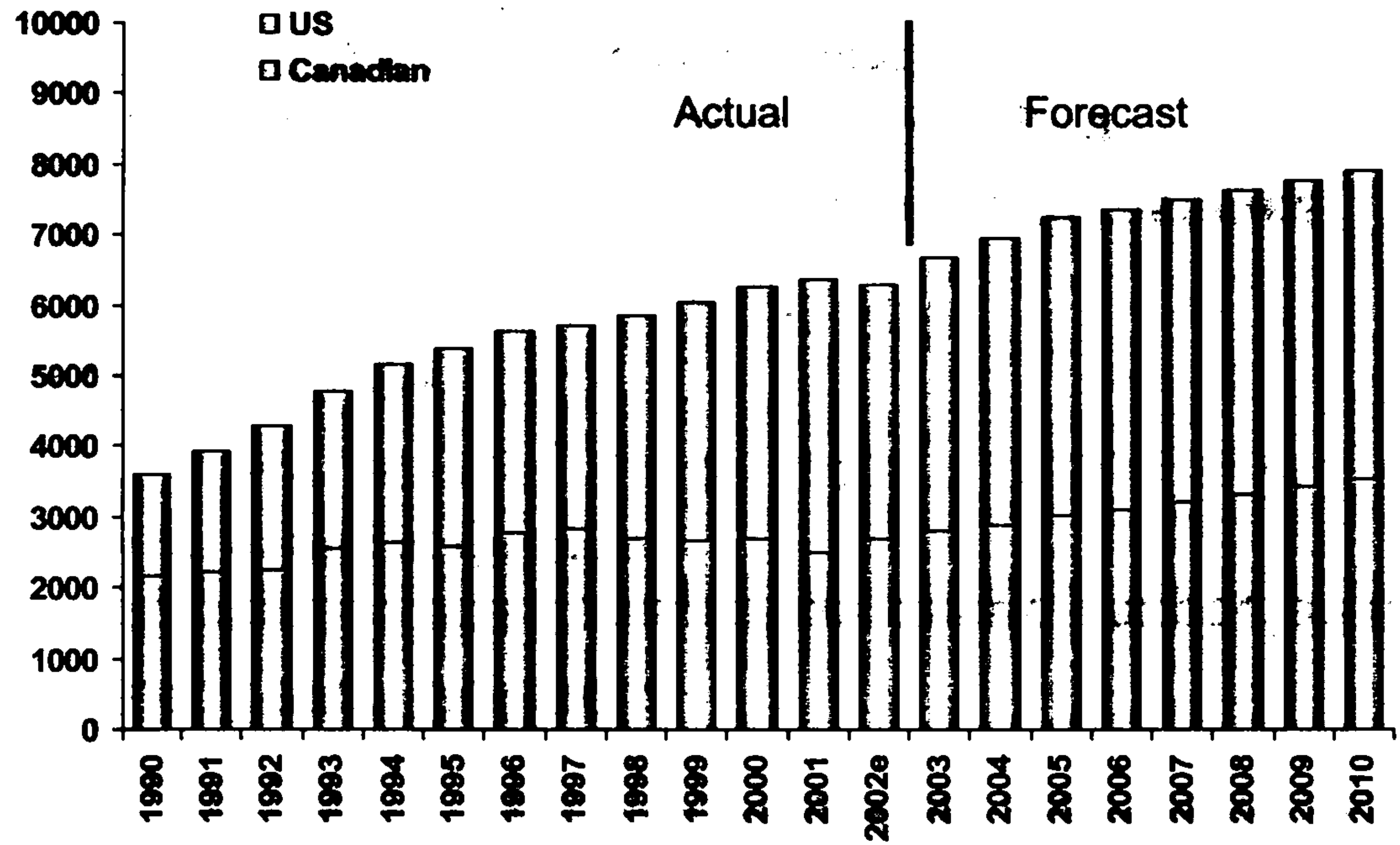
Source: CAPP


12,000
10,000
8,000
6,000
4,000
2,000
0
British Columbia
Saskatchewan
Alberta
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002F


West
East
Billion Cubic Feet
600
500
400
300
200
100
0
Last year's level - 459 Bcf
Current level - 459 Bcf
1/5/2001
3/5/2001
5/5/2001
7/5/2001
9/5/2001
11/5/2001
1/5/2002
3/5/2002
5/5/2002
7/5/2002
9/5/2002

CAPP

- **Short Term Outlook**
  - **Winter 2002/03 Canadian production expected to be flat to slight decline**
  - **Current price signal should signal increased drilling**
- **Longer Term**
  - **strong resource potential**
  - **need for conversion of resources to reserves**
  - **new supply sources being developed**
    - **CBM, North and Atlantic Canada**
  - **Moderate growth in exports to US**
- **Canadian public policy will be key**



Source: CAPP (actual), NrCan (forecast)

Good morning

My name is Alan Armstrong, and I am the Senior Vice President and General Manager of Williams Midstream. Williams Midstream operates one of the largest gathering networks in the United States and has facilities in the major supply basins of the Rocky Mountains, San Juan, and the Gulf of Mexico. I applaud the Commission's leadership in calling for a discussion of these important issues and appreciate the opportunity to speak today.

The task of building the infrastructure to deliver 30 TCF to market in 2010 is an enormous challenge. A critical part of that challenge will be to insure that natural gas that is produced in the Gulf of Mexico is delivered to market centers in the most cost-effective manner with the least amount of environmental disruption.

[**] Our vision of the future of the Gulf of Mexico's natural gas infrastructure is one of a robust and competitive environment where every pipeline that gathers offshore production to aggregation points onshore is able to compete on a level playing field to gather new production with any other existing or proposed pipeline. Each pipeline will gather and deliver production to onshore treatment and processing plants, which would be connected to multiple pipeline outlets and give producers the opportunity to access numerous market outlets depending upon where demand is the highest. This environment, which exists today in the onshore production basins, is proven and reliable, and has operated without significant state regulation. This is especially so in New Mexico and Wyoming where state gathering regulation is most minimal. Capital investment has substantially increased and production from these basins has grown. The result is increased competition for the commodity, which ultimately benefits the consumer. If this policy is applied to the offshore, it will ensure that the supply potential of the Gulf of Mexico is fully realized.

This future is consistent not only with conventional economics, but with the Commission's Order No. 636 policy. Within the framework of unbundling, the Commission has developed an onshore infrastructure that provides for the most efficient deployment of capital to transport natural gas to the market. The next logical step in this process is for the Commission to extend the same policies that were successful onshore, to offshore gathering. There are two necessary actions to achieving the onshore success. One is to eliminate firm-to-the-wellhead rate structures. The other is to develop a definition of gathering that consistently recognizes logical gathering systems that extend to points where there are multiple downstream transportation options. Usually this point is at the onshore processing plants.

[**] Full unbundling of services cannot be completed offshore without eliminating the firm-to-the-wellhead rate design. Firm-to-the-wellhead and other jurisdictional offshore pipelines compete with each other side-by-side to provide gathering service. This rate design is inconsistently permitted among jurisdictional offshore pipelines, and it prevents gas produced in the Gulf from economically accessing a full range of transportation options. The firm-to-the wellhead rate design effectively captures gas at the wellhead by making it economically inefficient to change pipelines downstream. As a result, the gas is

an economic captive of the first long-haul pipeline. The Commission should require all offshore pipelines to properly identify and unbundle their offshore gathering services.

[**] A second problem in the current regulatory environment is that the Commission's current policy for determining offshore gathering status is inconsistent and inhibits competition for gathering service. The current networks of both jurisdictional and non-jurisdictional offshore pipelines also compete with each other side-by-side to provide gathering service.

Transco and Williams Gas Processing proposed in their original spindown filings in 1996 a logical configuration for gathering to the plant outlet that I previously described. However, the spindowns configurations that have been approved were significantly different from what was proposed. The points of demarcation that the Commission deemed to be gathering are arbitrary and do more to compound regulatory confusion and inefficiencies than to address them. In each case, the point of demarcation resulted in rate stacking of both deregulated gathering and IT Feeder rates before the production could be delivered to a processing plant, or more importantly a market center. [**] On one of the Transco laterals proposed to be spundown, the North High Island lateral, the point of demarcation was deemed to be at a point located in the offshore under approximately 30 feet of water. Regardless of differences in pipe diameter, I find it difficult to distinguish between the gathering and transmission functions when the nature of the gathering service and the quality of the gas does not undergo any change until it reaches the plant complex onshore.

In conclusion Mr. Chairman and Commissioners, in order to accomplish the objective of maximizing the production capability of the Gulf of Mexico, we believe that the Commission should do two things. First, the Commission should ensure the completion of unbundling by eliminating the firm-to-the-wellhead rate structure. Second, the Commission should adopt a logical and broader definition of gathering for pipelines located in the OCS. Such a definition of gathering recognizes that facilities upstream of processing function as gathering, regardless of size. If these two things are done, important goals can be achieved. First, customers will be provided with more transportation choices, creating more competition for offshore and onshore transportation. Second, it will result in a level playing field where parties can compete more aggressively to provide offshore services that will achieve a more robust gathering industry. Complete unbundling of gathering and subsequent deregulation by the Commission would stimulate development of logical hubs for Gulf of Mexico production, and would allow supplies to be delivered to the market of highest demand in the most efficient manner. This policy will ultimately result in the most benefit to the consumer, which is the charge to the Commission under the NGA.

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REMARKS OF BERT KALISCH
ON BEHALF OF THE
AMERICAN PUBLIC GAS ASSOCIATION

FEDERAL ENERGY REGULATORY COMMISSION
Natural Gas Markets Conference
Docket No. PL02-9-000
Flexibility in Pipeline Operations

October 25, 2002

Good afternoon. My name is Bert Kalisch, and I am the Vice President for Government Relations with the American Public Gas Association. APGA is the national, non-profit association of municipally-owned, natural gas distribution systems, with 586 members, serving almost 3.5 million customers in 36 states. Overall, there are nearly 1,000 municipally-owned natural gas systems in the United States, serving more than 5 million customers, most of which are residential and commercial consumers. Thank you for permitting APGA to participate on this panel.

APGA joins in the thrust of Mr. Skains remarks on behalf of the American Gas Association. It is essential that growth in the gas industry not be accompanied by deteriorating service to LDCs. That is not an acceptable trade-off. LDCs have paid for the pipeline systems that span this country; and, these systems have been constructed to provide a certain level of service reliability to LDCs, whose primary constituents are residential and commercial consumers for whose protection the Natural Gas Act was enacted.

While we join with AGA and Mr. Skains in the main points raised during his comments, there is another related matter that APGA needs to emphasize to the Commission during this workshop.

APGA is not enamored with growth for the sake of growth. Growth, if not accomplished carefully and methodically, can have many unacceptable costs, ranging from environmental degradation to service degradation. As our remarks make clear, AGA and APGA share the concern about service degradation; APGA is also concerned about service reliability to high priority consumers in times of shortage.

APGA has oftentimes noted in pleadings at this Commission its serious concern with the over-reliance of the electric industry on natural gas for new electric generation, at the expense of fuel diversity for such new plants. Our concern about this wholesale migration to natural gas-fired electric generation is heightened by the fact that many of these new large gas-guzzling facilities do not provide for an alternate fuel capability. Thus, APGA anticipates that in emergency situations, electric generation plants, which historically have occupied the bottom rung of the curtailment ladder, will argue for enhanced status on the ground that without natural gas, there would be insufficient electricity for high priority users. Such an argument is tantamount to shooting your parents and then throwing yourself on the mercy of the court on the grounds that you are now an orphan.

APGA's concern is neither hypothetical nor farfetched. The electric generation plants in California were the beneficiaries of an Executive Order in 2001 that treated them as high priority users because of their need for natural gas.

APGA submits that fuel diversity goes hand in glove with national security, and the federal government should not rely on the marketplace to achieve that goal. The marketplace for a host of reasons (economics, construction lead times, environment, etc) is steering power plant builders to natural gas. APGA knows that the FERC has taken a hands-off position on this issue to date, on the grounds that it should not be concerned in certificate proceedings with how natural gas is used. APGA respectfully submits that the events of September 11 have made it crystal clear that such a laissez faire attitude, while if arguably justified prior to our national awareness of the very real threats facing this nation, can no longer be tolerated.

We must be concerned with the use of a valuable natural resource in such a fashion as to invite horrific outcomes in the event of a true national disaster. Fuel diversity, including making sure that generation plants built to primarily rely on one fuel can also run on an alternate fuel, must be a top priority for our federal energy regulators.

In brief, growth should not be viewed as an end in itself; it has positive as well as negative risks associated with it that the Commission must consider as it goes forward with the regulation of the natural gas industry.

Again, we thank you very much for allowing us to participate this afternoon.

FALCON GAS STORAGE COMPANY
FERC PRESENTATION ON OCTOBER 25, 2002

➢ **Substantial increases in gas-fired electric generation will exert severe stress on the existing natural gas transportation, storage and distribution infrastructure**

- The existing natural gas delivery infrastructure was built to serve residential, commercial and industrial gas markets – not the gas-fired generation industry.
- By 2004, an estimated 376,000 MW of gas-fired electric generation will be in service in the US (mid-case projection) – a 238% increase over the 158,000 MW in service in 1998. *See Figure 1.*
- Intra-day peak summer demand from gas-fired electric generation alone could reach the equivalent of 75 Bcfd – which exceeds current lower-48 flowing gas supply availability by nearly 15 Bcfd. *See Figure2.*

➢ **Unless the existing gas delivery infrastructure is upgraded to specifically address the operational and gas supply issues associated with gas-fired electric generation, gas delivery services to all classes of customers will be at risk**

- Virtually every pipeline requires that receipts and deliveries of gas be made on a ratable hourly basis across a 24-hour gas day. *See Figure 3.*
- Gas-fired electric generation facilities do not consume gas on this basis but rather in the same manner that electric power is dispatched – which can vary significantly from hour-to-hour within any given day. *See Figure 4.*
- Gas-fired electric generation facilities compete with LDCs and other shippers for pipeline capacity, including the swing capabilities necessary to meet highly variable intra-day gas supply delivery requirements. *See Figure 5.*

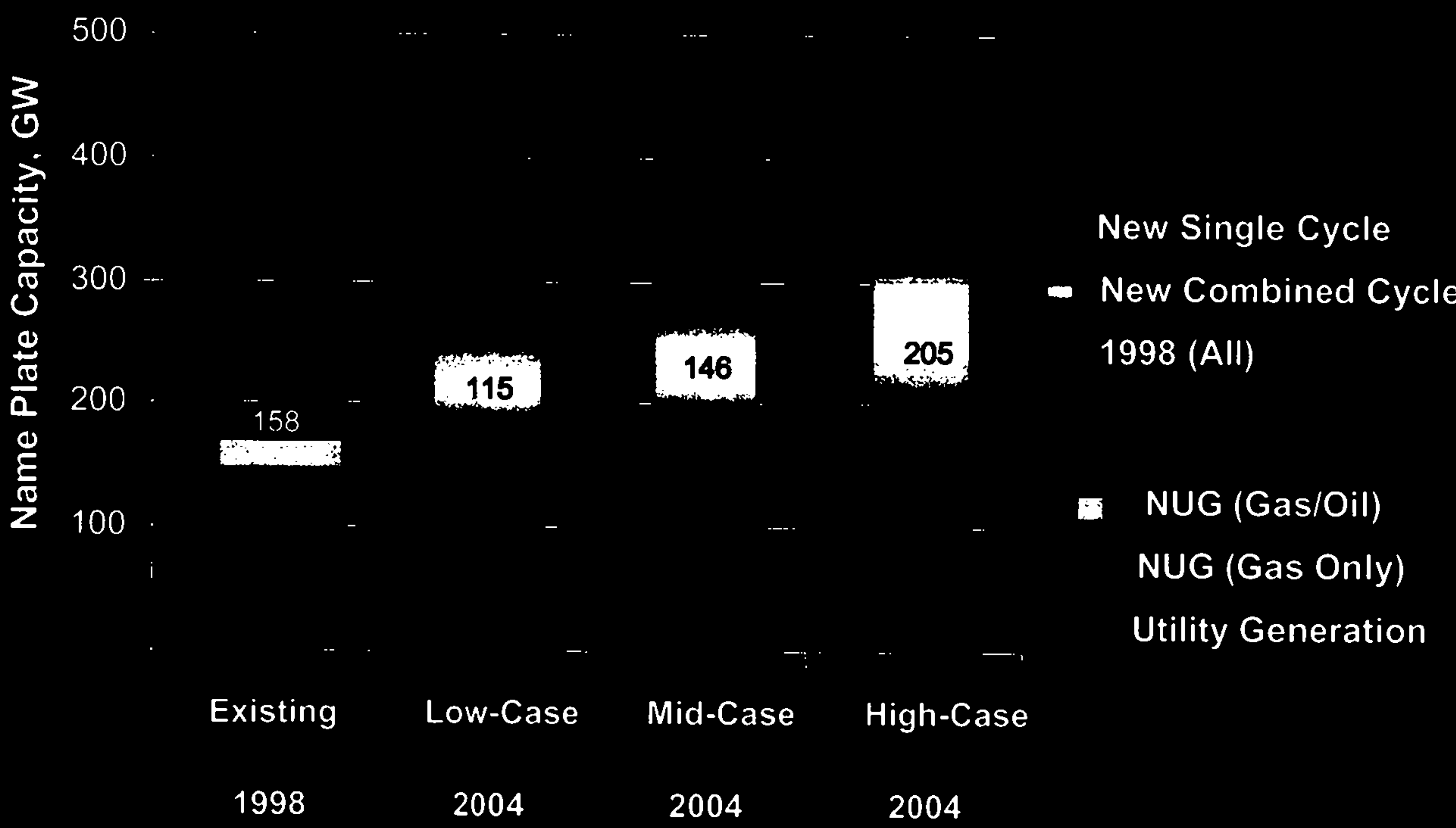
➢ **Natural gas storage is an essential component of the natural gas delivery infrastructure, but storage capacity additions have not kept pace with the growth in gas-fired electric generation capacity or peak-day gas supply requirements**

- 95% of US storage capacity is "single-cycle" capacity that was designed to serve temperature-sensitive RCI markets – not GFEG power plants.
- GFEG power plants must have access to a "load-following" gas supply that matches gas supply inputs with electric power outputs. *See Figure 4.*
- Without load-following capability, GFEG power plants will be subjected to substantial pipeline imbalance penalties (*see Figure 6*) – or worse, interruption of gas deliveries that prevent the generation of electric power during periods of peak demand. *See Figure 7.* Either could be financially devastating.

➢ **The Commission can help address this situation by doing the following:**

- Quickly approving the certification of new gas storage development projects
- Encouraging the retrofitting of existing single-cycle storage facilities to enhance service capabilities without rate cross-subsidies from existing storage customers
- Removing competitive barriers that exist in the form of anti-competitive pipeline tariff provisions that discriminate against third-party shippers and storage service providers by favoring pipeline services from pipeline storage and line pack

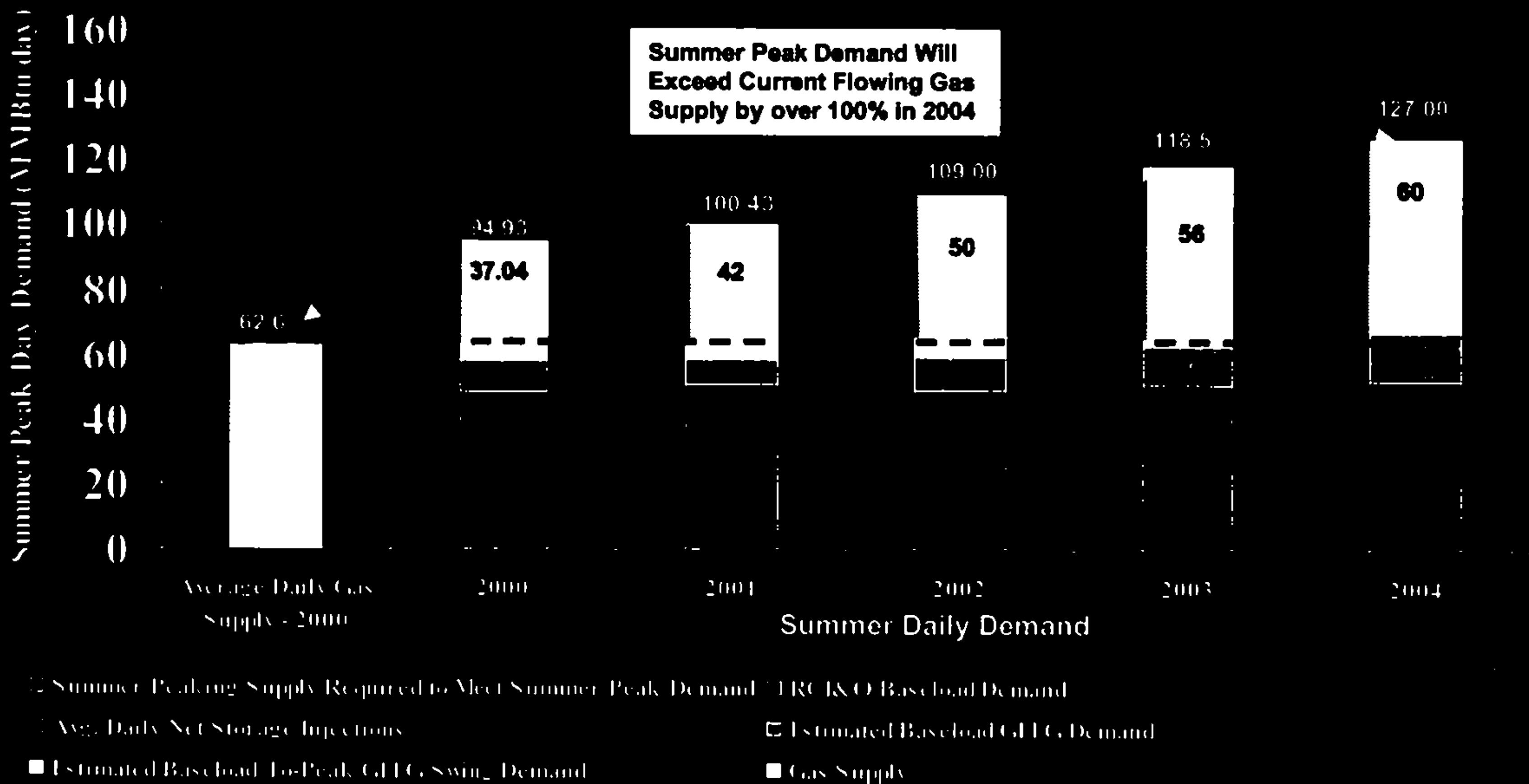
GFEG Existing and Forecasted Capacity



Summer Peak Day Demand and GFEG Load Swings 2000-2004

(Assumes 200.000 MW of New GFEG Capacity Placed In Service from 1998-2004)

Where is the Summer Peak-Day Deliverability Going to Come From?



FALCON GAS STORAGE

Major Regional Pipeline OFOs and Imbalance/Overrun Penalties*

Region	# of Pipelines	Pipelines Requiring Ratable Hourly Flow**	Pipelines Implementing OFOs	Pipelines Assessing Imbalance Overrun Penalties
West	5	3	4	4
Midwest	9	8	9	9
East	10	10	10	10
Southeast	2	2	2	2
Texas	2	2	2	2
Total	28	25	27	27

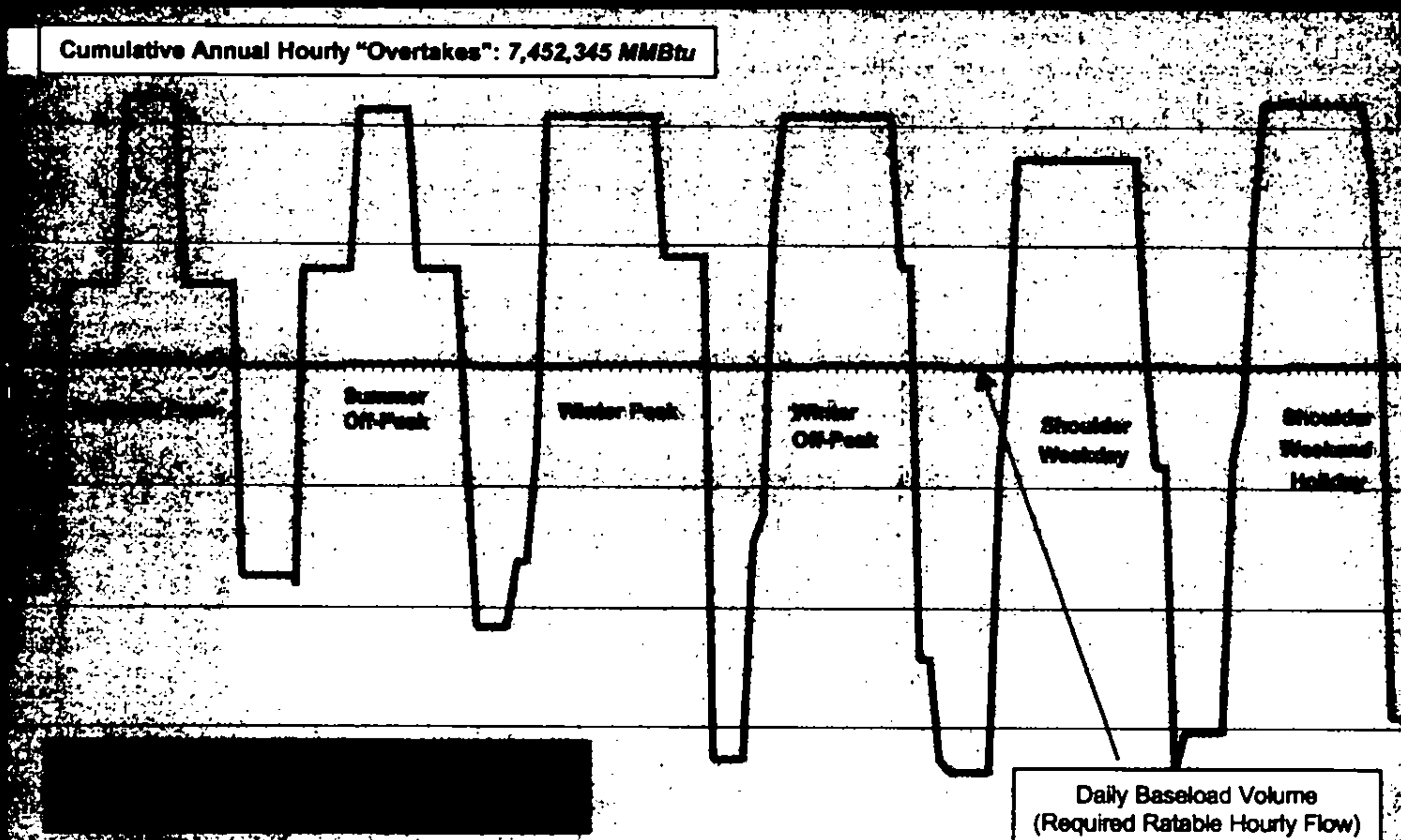
*Based on a survey of the tariffs of 28 of the largest interstate and intrastate pipelines
**Within a narrowly-defined tolerance (e.g., ±10%)

FALCON GAS STORAGE

Hourly Pipeline Imbalances Caused by Intra-Day Load Swings

For a Typical 750 MW Combined Cycle GFEG Facility

Overtakes/Undertakes from Pipeline Required To Balance Intra-Day Load Swings (MMBtu/hour)



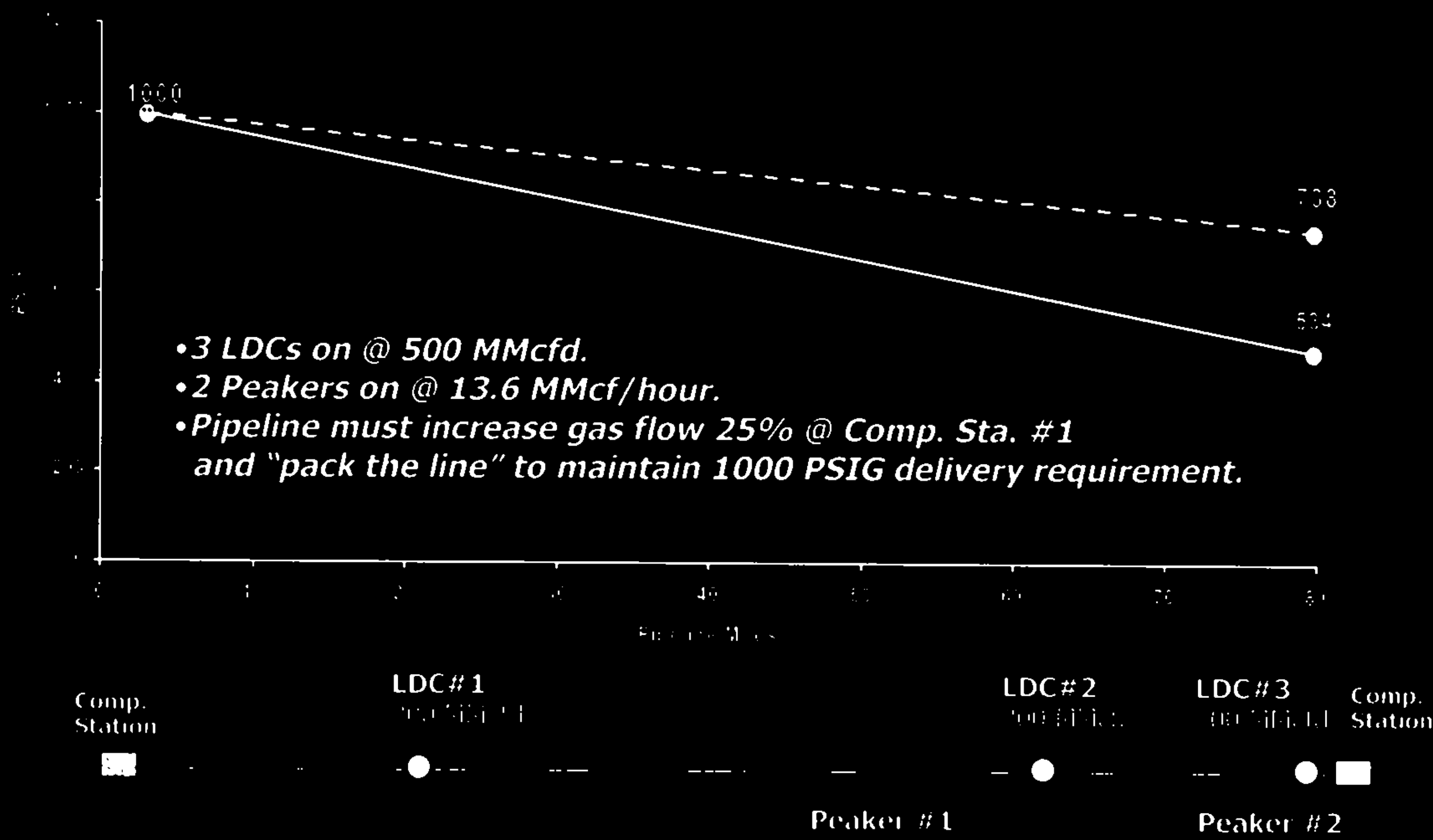
Hour of the Day

(Each tick mark represents 1 hour with each day's pattern beginning at midnight)

FALCON GAS STORAGE

Pressure Impact of Gas-Fired Generator On-Line

Hypothetical 36", 80-mile segment



FALCON GAS STORAGE

Imbalance Penalty Analysis

Type of Imbalance*	Volume (MMBtu)*	Total Imbalance Overrun Penalties @ $0.50/MMBtu	Total Imbalance Overrun Penalties @ $1.00/MMBtu
• Cumulative Annual "Overtakes"	7,452,345	$3,726,172	$7,452,345
• Cumulative Total Imbalances	12,297,662	$6,148,831	$12,297,662

* From Slide 4

FALCON GAS STORAGE

Lost Opportunity Cost
750 MW GFEG (CC) Facility

Duration of Service Interruption (Gas Deliveries Suspended/Curtailed)		Lost Opportunity Cost (No Power Dispatched)		
# of Hours	% of Annual Total*	@ $50/MWH	@ $100/MWH	@ $250/MWH
100	2%	$3.75 MM	$7.5 MM	$18.75 MM
200	4%	$7.5 MM	$15 MM	$37.5 MM
300	6%	$11.25 MM	$22.5 MM	$56.25 MM

* Assumes Total Annual Dispatch of 5,000 Hours (57% Annual Load Factor)

FALCON GAS STORAGE

Docket No. PL02-9
Session IV: Flexibility in Pipeline Operations

NiSource Pipeline Group Outline of Comments

Carl Levander

- The issue of defining a pipeline's "level of service" is one that should **not** be done on a generic basis. Differences in pipeline tariffs and services, system operations and capabilities and shipper requirements lead for the need for it to be determined between individual pipelines and shippers.

- Historically, pipeline commitments to customers for delivery pressure and hourly flow rights have been addressed through a variety of different mechanisms: individual rate schedules, customer settlements, tariff definitions, or as individual items in the service agreements. Some pipeline tariffs or contracts state maximum levels of flexibility and others simply provide the ability to impose operational controls, where necessary.

- Columbia has addressed these service reliability issues through individual customer contracts relating to both minimum pressure and hourly flow rights. Customer needs on these and other issues are addressed through contract negotiations. To the extent current service commitments are insufficient, they should be addressed through negotiation of individual contract provisions.

- The near-term expiration of many service agreements provides pipelines with incentives to respond to customer needs and to negotiate service commitments with customers. Our experience is that current customer contracts are modified on an ongoing basis to reflect changes in operational needs and customer requirements.

- Recent attention has focused on pipeline's obligations to provide minimum delivery pressures and the impact of serving new gas-fired electric generating facilities on these pressure commitments as well as on hourly flow flexibility.

- The addition of new electric generating plants to the pipeline system will affect pipeline operations. However, Columbia's experience has been that power generators are willing to sign up for firm service where necessary to meet their load profile, which supports needed capacity expansions. In these situations, sufficient mainline facilities will be added to ensure that all contractual service commitments will continue to be met. Where generators do not hold firm capacity, existing tariff mechanisms protect rights of firm customers from operational harm.

- Columbia believes the definition of customer service rights in the future should follow the model utilized in the past—utilization of pipeline and customer-specific communication and negotiation.

Conversion Gas Imports, L.L.C.
Michael M. McCall
President and CEO

To the Commission,

It is requested that the following comments be included in the transcript of the Natural Gas Markets Conference, October 25, 2002, Docket No. PL02-9-000.

Conversion Gas Imports, L.L.C. and the National Energy Technology Laboratory, U.S. Dept of Energy, entered into a cooperative agreement, September 30, 2002, to perform a research project (DE-FC26-02NT41653) titled, "Examine and Evaluate a Process to Utilize Salt Caverns in the Receipt of Ship Borne Liquefied Natural Gas (LNG)". The project is funded 80% by the DOE, and 20% by a combination of BP America Production Company, Bluewater Offshore Services, and HNG Storage Company.

The patented and patent pending technologies that are the subject of this research project have the potential to radically improve the security of LNG import facilities, reduce the costs of construction and operation of LNG import facilities, and significantly increase the capacity both to store gas imported as LNG and to subsequently deliver it to the US pipeline grid. As a part of the DOE Project, both onshore and offshore LNG receiving terminal sites will be selected and conceptually designed using salt caverns to replace cryogenic liquid storage tanks. Preliminary indications are that such a terminal could store as much as 24 Bcf of natural gas and deliver that natural gas on an instantaneously available basis to the pipeline grid at rates as high as 3 Bcf/D depending on the capacities of the pipelines it is connected to. Such a terminal could be located in the Gulf of Mexico, far from populated areas and accessible to the most comprehensive gas pipeline infrastructure in the country. It is anticipated that a terminal utilizing salt cavern storage technology could reduce the unit cost of imported LNG by 20 cents per Mcf or about 60%.

This concept is both an anti-terrorist technology, using highly secure underground salt caverns for gas storage and an energy infrastructure reliability technology by providing high capacity storage to support gas demand swings and be replenished by sea borne cargoes. On that basis I would like the Commission to consider changes to the regulatory framework dealing with LNG import terminals to provide an accelerated review to encourage the adoption of new technologies.

Thank you for your consideration. There is additional information on the concept of utilizing salt caverns for LNG receiving and the DOE study on CGI's website at www.conversiongas.com.

Respectfully submitted,

Michael M. McCall

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Statement of
Stacey Gerard, Associate Administrator for Pipeline Safety,
Research and Special Programs Administration
U.S. Department of Transportation
Before the Federal Energy Regulatory Commission
At National Gas Markets Conference on
October 25, 2002

Good Afternoon. I am Stacey Gerard, Associate Administrator for the Office of Pipeline Safety(OPS), of the Department of Transportation's Research and Special Programs Administration (RSPA). I would like to provide a brief update on new safety initiatives which should improve performance of pipeline operators and improve confidence of communities about living safely with pipelines.

RSPA/OPS has adopted a new approach to safety regulation that requires a pipeline operator to provide additional protections to those areas where an accident could have the greatest consequence. These new protections are provided in integrity management programs. RSPA/OPS has already issued regulations requiring integrity management programs (IMP) for liquid pipelines, and we are in the final stages of proposing similar regulations for gas transmission pipelines.

IMP requires rigorous testing and followup. Followup includes prompt repair or other remedial action such as pressure reduction as well as consideration of additional preventative and mitigative measures. Equally important, IMP requires operators to analyze test results with other information they have about their pipelines to identify and address safety risks. IMP raises the bar for pipeline safety more than any other regulations in the past 30 years. The General Accounting Office and the National Transportation Safety Board have both issued reports in the past month which discuss the merits of this new approach.

A second important strategy we are working on is to have communities become more proactive in dealing with pipeline safety in preventing damage to underground pipelines; in planning for emergencies; in expediting approval of the permits necessary to repair existing pipelines; and in improving security against intentional attack on pipeline facilities. We are working on several initiatives to achieve these aims.

First, on Monday, we will announce a new partnership with the National Association of State Fire Marshals to help us improve community planning for and prevention of emergencies.

Second, beginning this year, we are deploying new regionally based Community Assistance and Technical Services inspectors. These inspectors will work with regional, state and local organizations with an interest in preventing damage to all underground facilities. They will offer technical support to local officials whose front line safety decisions in planning, zoning and rights-of-way monitoring directly impact underground utility safety. These inspectors will be available to address state and local questions about the safety of pipelines that may be raised in FERC's review of new pipeline construction applications. By addressing safety questions at the earliest stages of the review process, we hope to assist you in making the review process as efficient as possible.

Finally, RSPA helped establish an organization, the Common Ground Alliance, to address best practices in preventing damage to underground pipelines. Best practices in local planning and excavation activities can reduce the risk of damage to underground pipelines.

We have stepped up our efforts to work with FERC staff on these initiatives to maximize the effectiveness of our respective agency efforts.

In conclusion, as the primary regulator of the safety of our national pipeline infrastructure, we stand ready to find ways to improve the safe and reliable performance of the pipelines and to work with you to improve America's confidence living safely with pipelines is, in fact, an achievable goal.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Natural Gas Markets Conference) **Docket No. PL02-9-000**

COMMENTS ON BEHALF OF
PROCESS GAS CONSUMERS GROUP,
AMERICAN FOREST & PAPER ASSOCIATION,
AMERICAN IRON AND STEEL INSTITUTE,
GEORGIA INDUSTRIAL GROUP,
INDUSTRIAL GAS USERS OF FLORIDA,
FLORIDA INDUSTRIAL GAS USERS AND
UNITED STATES GYPSUM COMPANY

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Notice of Conference issued September 12, 2002 and the subsequent Notice of Public Conference and Agenda issued October 18, 2002, the Process Gas Consumers Group, American Forest & Paper Association, American Iron and Steel Institute, Georgia Industrial Group, Industrial Gas Users of Florida, Florida Industrial Gas Users and United States Gypsum Company (collectively, the "Industrials") hereby submit the following preliminary comments addressing matters set for discussion in Session IV – "Flexibility in Pipeline Operations – Pipeline infrastructure and its ability to meet the need of all future customers."

As threshold matter, as to the gas commodity, the pipeline infrastructure and pipeline service options, we generally believe that more is both better and necessary to the economic viability of this Nation. As to the gas commodity, we hope that policies will be adopted to ensure an adequate supply of natural gas at reasonable prices, so that there is never again a fight over which class of customers is entitled to have access to the gas commodity. In this vein, we support the producers in their call for increased access to public lands and further support national policies leading to a more balanced fuel portfolio.

As to the pipeline infrastructure, we have long been an advocate for streamlining the pipeline certification process in order to help ensure development of the increased infrastructure necessary to bring supplies of natural gas to the market and to promote competitive transportation options. We fully support and applaud the Commission for the steps it has taken to date, such as its ongoing efforts to streamline and coordinate the certification process and to process certificate applications with all due speed.

As to access to transportation services and pipeline service options, the Industrials have been strong advocates for new and varied open access service options on the natural gas pipeline grid to provide all shippers with increased flexibility. In general, we have found the pipeline community to be responsive to changing marketplace conditions that create demands for new and innovative services, and we fully support the efforts to improve pipeline service to all shippers. Moreover, we have participated in an ongoing dialogue with other segments of the industry in order to determine how best to serve both the new generation load as well as the historic industrial load, recognizing that these two sets of pipeline customers may have very different load profiles.

Perhaps most importantly, we are not here to just say NO! Indeed, we believe that appropriate policies and regulations can be developed to permit pipelines to serve all types of pipeline customers in a non-discriminatory manner, without degrading the existing service received by current firm shippers and imbedded in the current rate structure.

As we engage in this dialogue with the Commission and other stakeholders, we offer several overall principles that we believe must guide the development of any policy governing services to electric generators. These principles reflect the Commission's open access policies:

- service should be offered as a tariffed, firm service and made available on a non-discriminatory basis;

- service should not strip current operational flexibility from existing firm shippers;

- service should have a firm scheduling priority equal to other firm service – *i.e.*, no super firm;

- pipelines must have the ability to require reasonable operational and tariff safeguards to prevent disruption of system flows, pressures and operations, and to prevent harm to other shippers;

- implementation procedures should include a detailed filing by each pipeline demonstrating: (1) that its proposals are necessary; (2) that the pipeline has the capacity and operational ability to provide the service without degrading existing firm shippers' service, or, what facilities will be necessary to provide the new service to prevent degradation of existing firm rights, (3) the proposed service rights are consistent with Commission policies, and (4) the costs, rates and revenue effect of the service;

- rates for any new service should fully recover the costs of the facilities, operational flexibility and other benefits provided; and

- pipelines must continue to make traditional FTS available to shippers and must not divert all firm capacity solely to new generator services.

In our view, FERC's role in this debate at this stage is somewhat limited. Although it might be useful for the Commission to comment on the principles that should govern these services, the operationally sensitive nature of these services requires that the details be hammered out in pipeline-specific proceedings where the capabilities of each pipeline can be examined and the appropriate rates and parameters set for any new service.

We look forward to the discussion at the October 25th conference and the continued dialogue on this important issue.

Respectfully submitted,

Dena E. Wiggins

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On behalf of:
Process Gas Consumers Group,
American Forest & Paper Association,
American Iron and Steel Institute,
Georgia Industrial Group,
Industrial Gas Users of Florida,
Florida Industrial Gas Users and
United States Gypsum Company

October 25, 2002

LNG - OPPORTUNITY

To Meet Growing U.S. Demand

Ron Billings. Vice President. Global LNG
FERC - Oct. 25. 2002 Conference

ExxonMobil Gas Marketing Company

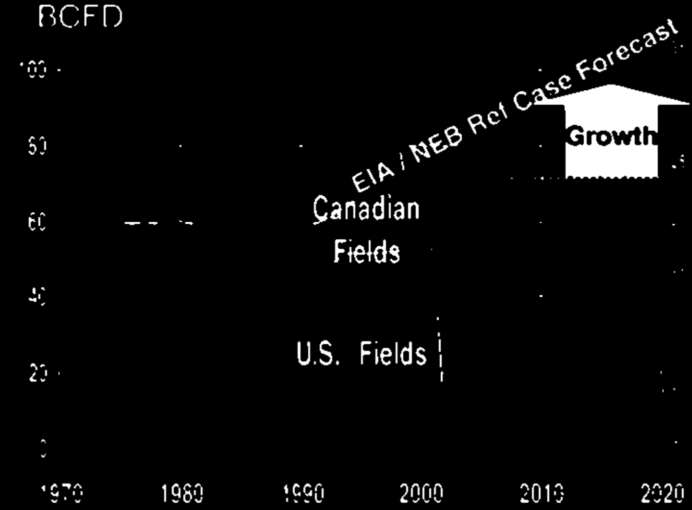
- A leading Global LNG Supplier
  - 30 yrs experience in all aspects of LNG
  - Participation in 3 world class LNG projects: Arun, RasGas, Qatargas
  - 300+ LNG cargoes per year

- Sales to global markets
  - Traditional LNG markets
    - Asia: Japan, Korea
    - Europe: Spain, Turkey
    - New Sales: Italy
  - Entering new LNG markets
    - India
    - the UK entry point into the liquid European market

- Access to 185 TCF of natural gas resources

ExxonMobil views U.S. as a potential key market for LNG

LNG - Cost Competitive/Safe Supply



- U.S. needs new gas supply to meet energy growth demand
- Non-traditional sources will be needed

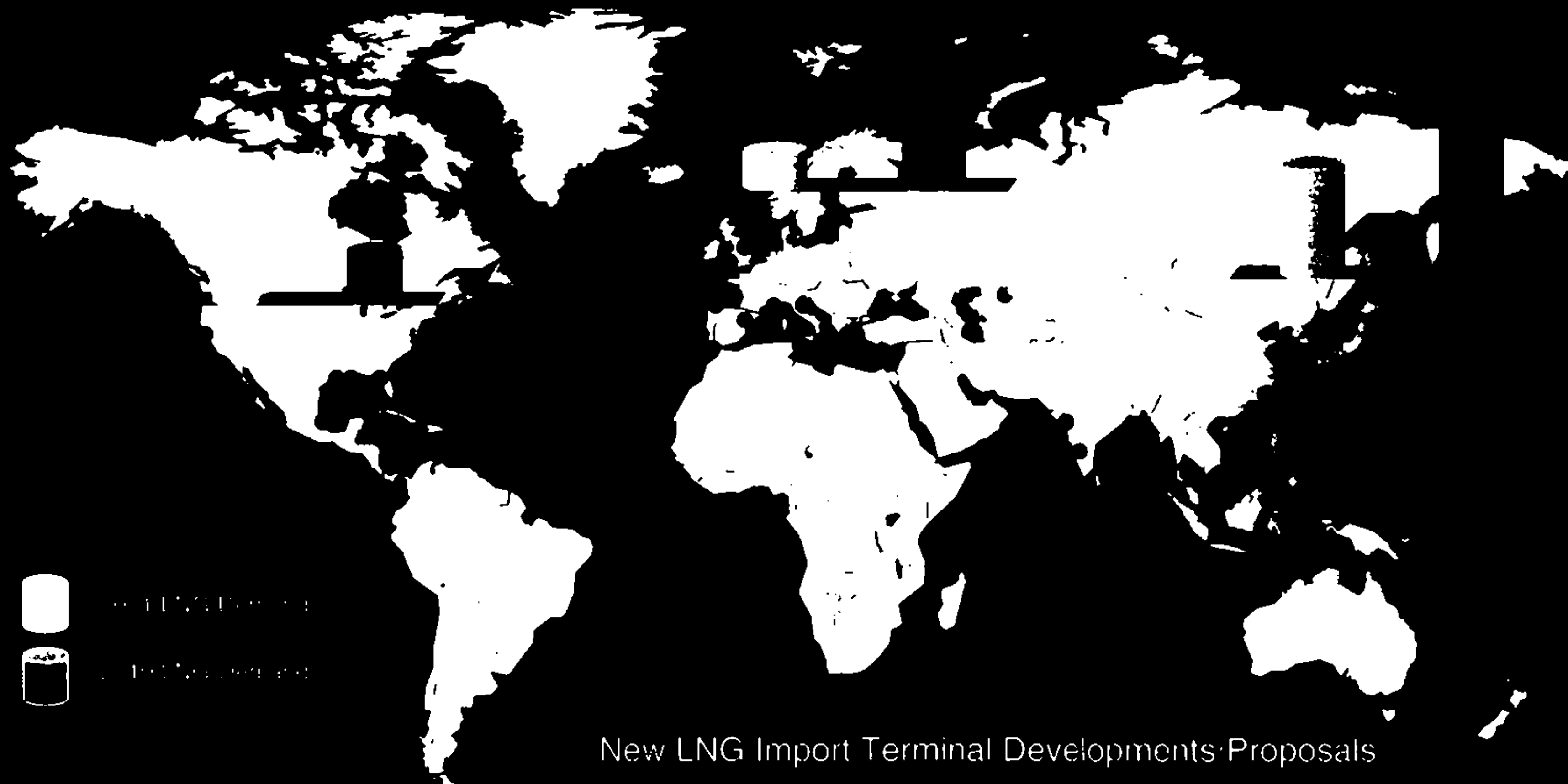
- Multiple new LNG supplies available
- LNG has exemplary safety record

LNG is a safe and reliable source of gas to meet the U.S. demand. competitive with customers' alternatives

LNG - A Competitive Global Market

World gas demand is growing at 2.6%* per year

LNG demand is expected to more than double by 2010



New LNG Import Terminal Developments/Proposals

LNG supplies are seeking the best markets:
Economically viable markets with fewest <u>barriers</u> to entry

Market Access

LNG Chain

Terminal is critical path
to market access

- Critical mass is essential for supply development
  - Reserves required: 7 - 10-TCF fields
  - Chain investments required: $2.0 - $5.0 Billion
  - Large Volumes: 500 MMCFD to 1.0 BCFD
  - Typical contracts: long term 20-25 years
- Aligning of volumes throughout the chain is essential

Uncertainty of market access is most significant barrier to overcome

- Cannot commit to large capital expenditures: Field development. Liquefaction plant. Shipping .... without and market access

Regasification terminal is a critical link between supply and market

Regulatory Barriers

Existing regulatory requirements stifles LNG import terminal development in U.S.

- Open Access — Uncertain Results
  - Lengthy open season process
  - Does not guarantee terminal capacity access
  - No terminal development or sub-optimal terminal size
  - Difficult and inefficient shipping logistics
  - Impedes development of new lower cost LNG technologies
  - Negative impact on project financing
- Cost of Service
  - Limits commercial flexibility
  - Potential for consumer to share risk

Current regulations are barriers to U.S. LNG import terminal development

Way Forward

Rely on market forces rather than economic regulation of LNG terminals

- Maintain oversight process (NGA § 3)
  - Approve imports
  - Lead agency to facilitate process for new LNG import terminals

- No need to establish LNG import terminals as "Natural Gas Companies" - interstate transportation <u>*begins*</u> downstream of the LNG import terminal
  - Eliminate "open access" requirements (NGA § 7)
  - Eliminate "cost of service" regulation (NGA § 4)
  - Allow competitive market to work: permit companies to negotiate guaranteed terminal capacity rights, terms and rates

FERC is integral to increasing U.S. access to safe and reliable gas supply