Key Issues Facing Gas Utilities and State Public Utility Commissions

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Topics

- The implication of a tight natural gas market for gas utilities and state regulation
- New ratemaking proposals in response to high natural gas prices and revenue shortfalls
- Gas affordability issues and implications for gas utilities
- Short-term and long-term projections of future natural gas prices and market conditions

Proposed New Ratemaking Methods

Basic Arguments by Gas Utilities for New Ratemaking Mechanisms

- Prevailing conditions make it difficult to measure with adequate precision certain costs and sales in a test year
- Asymmetrical distribution of certain costs and sales around some baseline or normalized level (e.g., the likelihood of gas sales per customer falling below the test year level is much greater than the likelihood of sales exceeding the test year level)
- <u>The challenge for state commissions</u>: each mechanism has varying effect on advancing and hindering the core principles and policy objectives underlying ratemaking

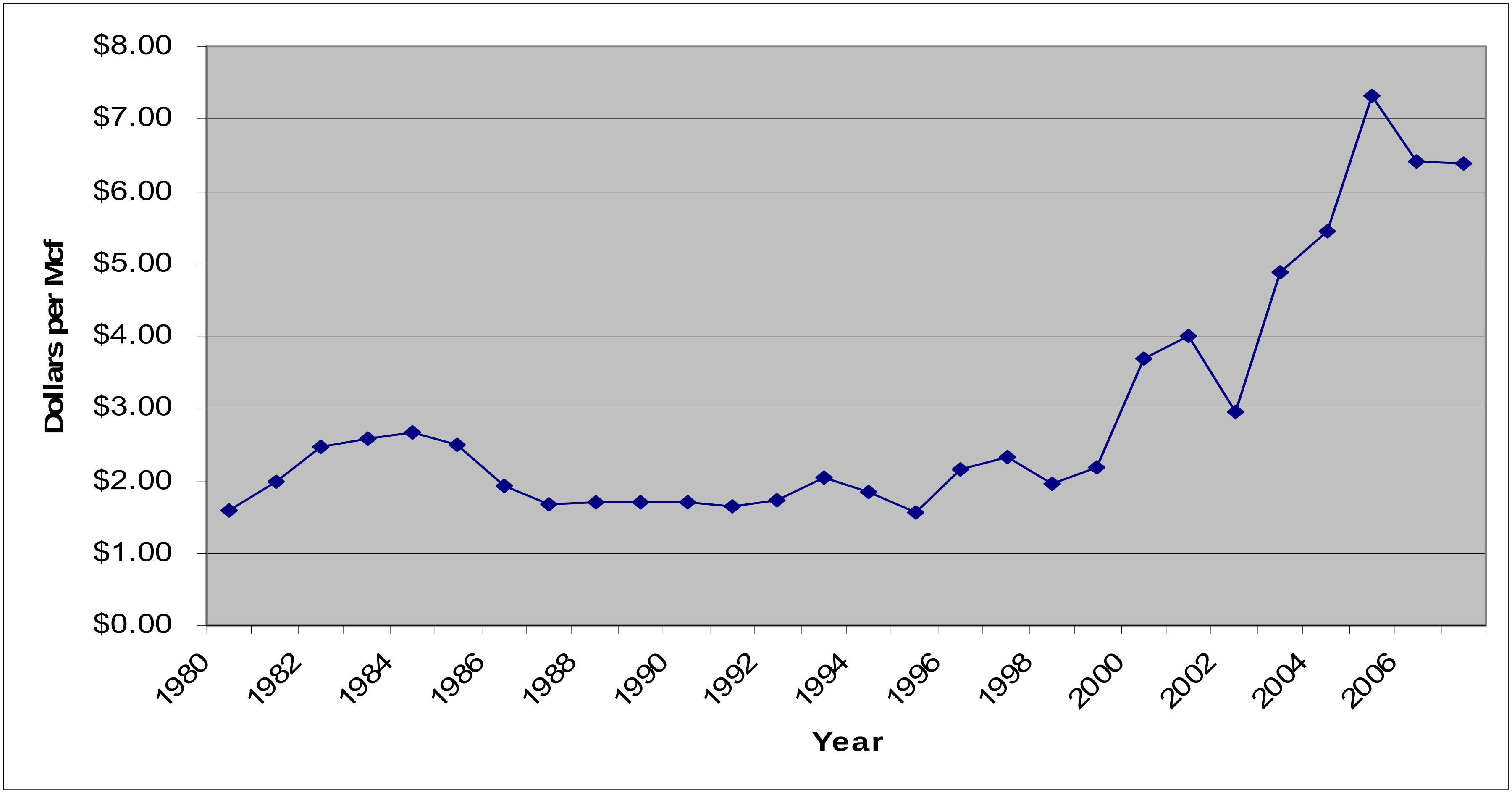
Examples of New Ratemaking Methods

- Revenue decoupling (RD) rider
- Straight-fixed variable (SFV) rate design
- Earnings sharing mechanism
- Tracker for bad-debt costs
- Tracker for pipeline-integrity-management costs
- Tracker for pipeline-replacement costs
- Tracker for utility energy-efficiency costs

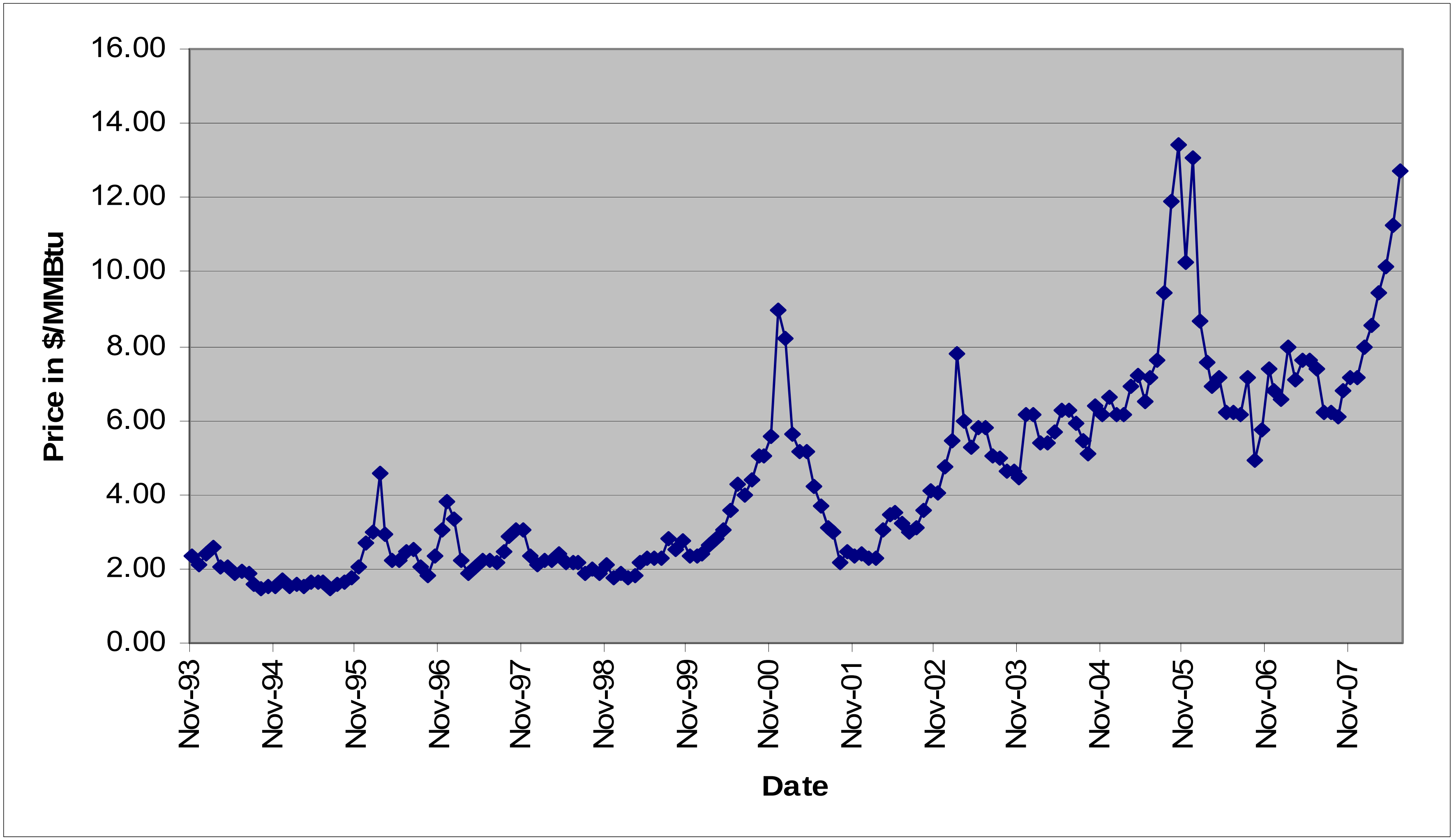
Cost Trackers (or Riders)

- A utility adjusts its rates to recover certain costs without a formal rate review
- These costs can include those that deviate from some baseline (e.g., bad-debt costs that exceed the level implicit in current rates determined by a commission in the last rate case)
- These costs can also include zero-based expenses; a commission might allow a utility, for example, to recover all of its costs in promoting energy efficiency outside of a rate case review
- One justification for a cost tracker is the inadequacy of using historical cost to predict future costs
- A tracker has the intent of stabilizing a utility's earnings and reducing the likelihood of future rate cases
- On the downside, a tracker could cause a utility to have less incentive to control its cost with the diminution of regulatory lag; another concern is that a tracker would shift risks to consumers, since supposedly the utility could more easily pass through excessive costs, or any cost increase, to consumers

Wellhead Natural Gas Prices, 1980-2007



Historical Henry Hub Prices,1993-2008



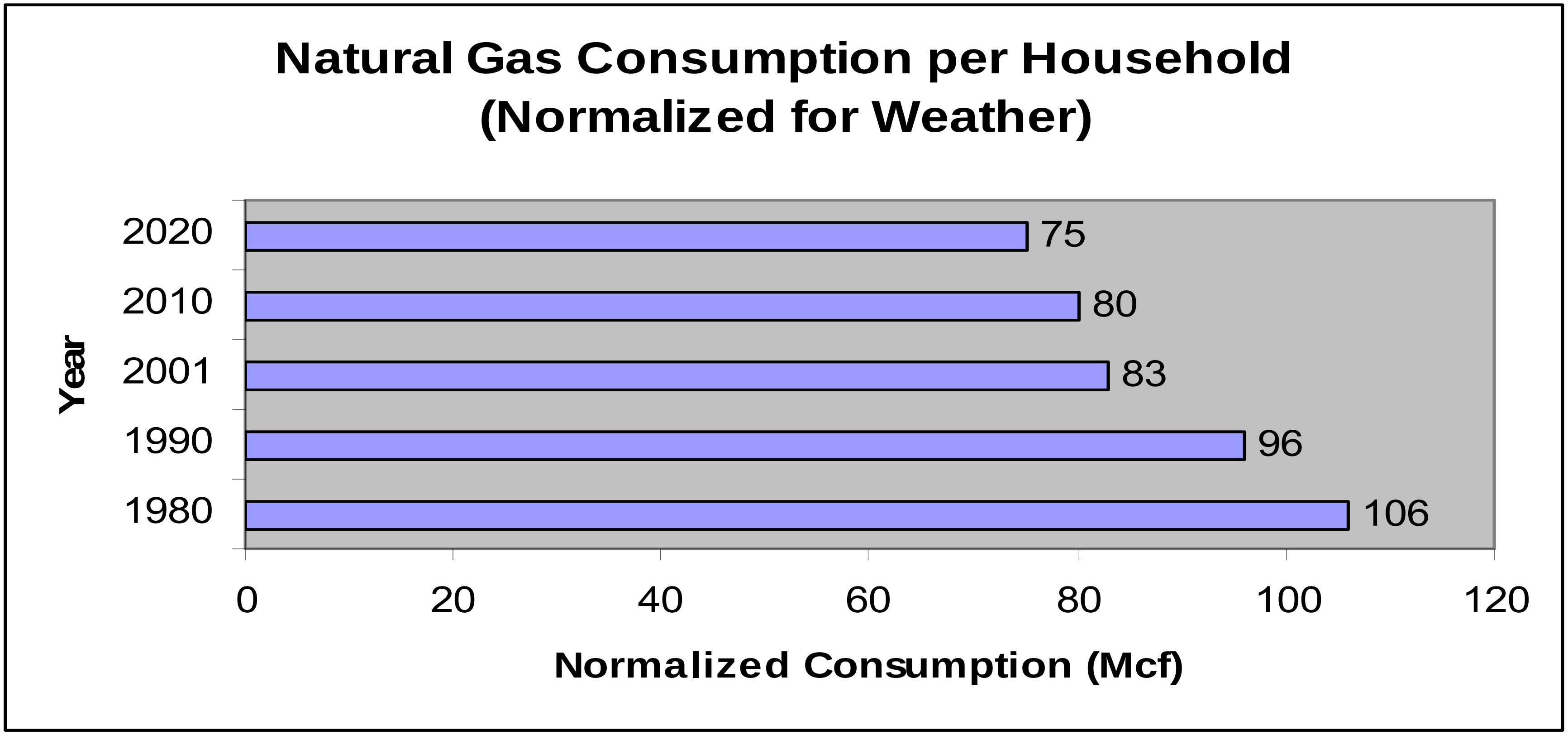
Consequences of High and Volatile Wholesale Natural Gas Prices

- More customers find natural gas unaffordable, especially low-income households
- Energy conservation, whether customer-induced or utility initiated, becomes more beneficial
- Fuel-switching becomes more likely (e.g., residential customers switching to electric heat pumps)
- Price-elasticity effect becomes more pronounced (i.e., higher consumer response to prices)
- Utility bad-debt expenses increase
- Both the utility and its customers generally face more risk
- Hedging becomes more important for both the utility and its customers (e.g., increased price predictability and stability offers value to consumers)
- Utility customers become less satisfied with their utility service and regulatory oversight
- Overall, the gas industry becomes less stable with usage levels, gas bills and utility earnings more volatile and uncertain

The Impact of Rising Gas Costs and Energy-Efficiency on LDCs' Gas Revenues

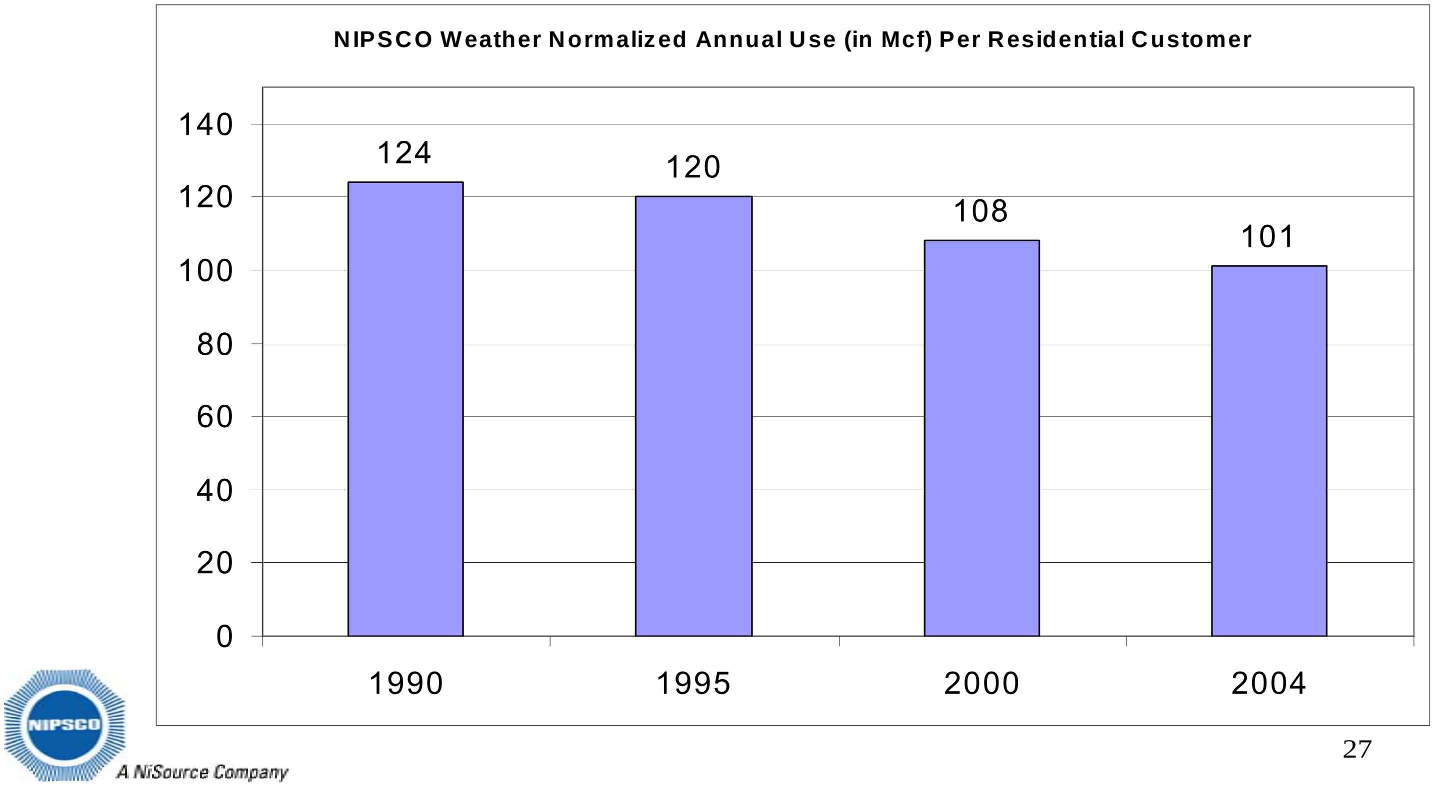
- Between 1980-2005, 15 million new residential gas customers (35% increase)
- Over the same period, total residential gas consumption increased by only 0.1 Tcf (2.1% increase)
- Usage per household (normalized for weather) has continuously declined over this time for various reasons
- Most gas utilities filing rate cases in recent years have experienced a decline in usage per customer over the past two decades
- Although parties to these proceedings generally have not disputed this happening, some have questioned whether this decline will continue in the future

Declining Gas Consumption per Household since 1980 (*source: AGA*)



Example for a Gas Utility

NIPSCO's Residential Usage also on the Decline



Recent Econometric Study*

- Factors like new building codes and appliance efficiency standards, in addition to rising gas prices, have contributed to the downward trend of gas usage per customer over the past 20+ years
- *Δ Consumption per Household (%) = -0.18·Real Price Change (%) + Annual Trend (-1%) ·Number of Years* (example for 2000-2006: with a 44% price increase, consumption per household estimated to fall by 13.9%, or 2.2% per year)

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* Frederick Joutz and Robert P. Trost, *An Economic Analysis of Consumer Response to Natural Gas Prices*, prepared for the American Gas Association, March 2007

Illustration of Effect of Declining Sales on Earnings

– Accounting relationships:

$$E^* = R^* - FC$$

$$\Delta Q \times P = \Delta R = \Delta E$$

$$\Delta R/E = \Delta E/E = \Delta ROE/ROE^*$$

where * indicates targeted or baseline, Δ = change, E = earnings to equity shareholders, R = revenues, FC = fixed costs (including the interest on debt), Q = sales level, P = base rate, and ROE = rate of return on equity

– *Example*: R* = $400 million; FC (all costs except the return on equity) = $360 million; ROE = 12% (or authorized earnings to common equity holders = $40 million

Illustration of Effect of Declining Sales on Earnings -- *continued*

– Assume that all distribution (non-gas) costs are fixed
– Assume that revenues fall 1% (or $4 million) short of the targeted revenue (R*) because of an unexpected price-elasticity effect
– The decrease in earnings to common equity holders would equal $4 million, which is a decline of 10%; this translates into a decrease of ROE of also 10% (or 120 basis points) or from 12% to 10.8%
– **In sum, the decrease in revenues of 1% translates into lower earnings to equity holders of 10%**

Setting the Base Rate: Test Year Parameters for the Residential Class

Revenue requirements (after cost allocation)	$97.5 million
Number of customers (latest historical count)	500,000
Average usage per customer (latest historical count, assuming normal weather)	90 Mcf
Total gas usage	45 million Mcf
Customer charge	$5 per month
Customer charge revenues	$30 million
Volumetric charge	$1.50 per Mcf
Volumetric revenues	$67.5 million
Volumetric revenue per customer	$135
Authorized earnings to common equity shareholders (@ pre-tax ROE of 10%)	$10 million
Total revenues from distribution service	$97.5 million

The Standard Two-Part Tariff: Applying the Previous Numerical Example

- The following arithmetical expression shows the standard two-part tariff for base rates set by gas utilities

$$B_i = C + p \cdot q_i$$

  where the non-gas component of the total bill for customer i (B_i) equals the sum of the customer charge (C) and the volumetric distribution charge (p) times the amount of gas consumed (q_i)

- The two-part tariff from our previous numerical example

$$\mathrm{B_i = \$5\ per\ mo. + \$1.50 \cdot q_i}$$

  Assume that a customer uses 20 Mcf of gas in a particular month. The total non-gas portion of her bill would be $35.

Consequences of Standard Two-Part Tariff

- If a two-part tariff recovered all the fixed costs in the fixed charge and only the variable costs in the volumetric charge, it would coincide closer to economic principles (such a rate structure is often referred to as a straight-fixed variable [SFV] rate design)
- In practice, however gas utilities using the two-part rate structure recover much, if not most, of their fixed costs in the volumetric charge

Consequences of Standard Two-Part Tariff -- *continued*

- The recovery of some percentage of the utility's fixed costs depends upon the level of gas usage.
  - When usage falls (or rises), because of factors such as abnormal weather, the business cycle, changes in customer behavior, and appliance and building characteristics
  - A utility's earnings also fall (or rise) because the utility must pay the fixed costs regardless of the revenue level
- Because earnings fall with lower usage, the utility has a disincentive to promote energy conservation, especially between rate cases.
- If the volumetric charge includes only recovery of variable cost, then a drop in sales reduces costs and revenues proportionately, with no effect on earnings

Consequences of Standard Two-Part Tariff -- *continued*

- High usage customers tend to subsidize low usage customers. Disproportionately, the utility recovers its fixed costs from high usage customers, even though much of these costs are more customer-related than usage-related
- The change in a customer's gas bill from increased usage (for example, because of abnormally cold weather) would be greater than if the usage charge excluded all fixed costs

Ratemaking Proposals Addressing the Problems of the Standard Two-Part Tariff

- Revenue-decoupling (RD) tracker
- Straight-fixed variable (SFV) rate design
- Earnings sharing mechanism
- Shifting of more fixed costs to the customer charge
- Declining-block rate

Highlights of Recent Activities on Revenue Stabilization Mechanisms

- Lot of activity on the natural gas side for revenue decoupling and other revenue stabilization mechanisms
- Beginning to see renewed interest in the electricity sector and somewhat less for the water sector
- Revenue stabilization has become an important goal for gas utilities, who have proposed new ratemaking mechanisms; these include *revenue decoupling, straight-fixed variable rate design, earnings sharing, higher customer charges, and declining block rate*

Revenue Decoupling (RD)

- Outside of rate-case rate adjustments for distribution non-gas service based on the difference between actual revenues and some specified revenue baseline (e.g., the non-gas revenues per customer embedded in the test year)
- “True-up” mechanism that adjusts non-gas base rates between rate cases based upon differences between actual revenues and baseline revenues

Revenue Decoupling -- *continued*

- Revenue shortfalls or surpluses placed in an account balance for later recovery by the utility or reimbursement to customers; recovery or reimbursement done monthly, quarterly or some other regular interval
- Recovery of fixed costs based on baseline revenues, rather than actual sales, hence the term “decoupling”
- A (hard or soft) revenue cap, on either a per customer or total customer-class basis

The Rationale for Revenue Decoupling

- Eliminates the disincentive for utilities to promote energy efficiency
- Standard rate design places the utility at risk for recovering its fixed costs previously deemed to be prudent, with the risk increasing in recent years
- RD superior to alternative rate designs in achieving revenue stability and promoting energy efficiency
- Represents an incremental change in ratemaking practices that would significantly advance some regulatory objectives while having little effect on other objectives

Revenue Decoupling – Previous Numerical Example: Test Year Versus Actual

Parameter	Test Year	Actual
Revenue requirement	$97.5 million	$97.5 million
Number of customers	500,000	500,000
Average usage per customer	90 Mcf	88.2 Mcf
Total gas usage	45 million Mcf	44.1 million Mcf
Customer charge	$5 per month	$5 per month
Customer charge revenue	$30 million	$30 million
Non-customer-charge revenues	$67.5 million	$66.15 million
Volumetric charge	$1.50 per Mcf	$1.50 per Mcf
Volumetric revenue per customer	$135	$132.30
Total revenues	$97.5 million	$96.15 million
Revenue shortfall	-	$1.35 million
Revenue shortfall as % of revenue requirement	-	1.38%
Pre-tax earnings to common equity shareholders	$10 million (10% ROE)	$8.65 million (8.65% ROE)
Revenue shortfall as % of customer's bills (assuming $10 per Mcf gas cost)	-	0.26%

Revenue Decoupling Adjustments

- Revenue shortfall = $1,350,000
- Revenue adjustment per Mcf = $1,350,000/44,100,000 Mcf = $0.0306 or 3.06 cents
- Revenue adjustment per customer = $1,350,000/500,000 = $2.70
- Observations
  - Revenue adjustment results in a very small increase in customers' gas bills
  - A decline in gas usage of 2% below the expected level results in the pre-tax ROE dropping by 13.5% or 135 basis points

Revenue Decoupling under Different Labels

- Conservation margin tracker
- Conservation-enabling tariff
- Conservation tariff
- Conservation rider
- Conservation and usage adjustment tariff
- Innovative ratemaking
- Conservation tracker allowance
- Incentive equalizer
- Delivery margin normalization
- Usage per customer tracker
- Customer utilization tracker
- Trial billing determinant adjustment clause rider

Straight-Fixed Variable (SFV) Rate Design

- Let us assume in the previous numerical example that fixed costs make up 90% of the non-gas costs and that a utility recovers all of the fixed costs in the customer charge, with the remaining 10% recovered in the volumetric charge
- The fixed monthly charge would then equal $14.60 and the volumetric charge would equal $0.217 per Mcf (Recall that under standard rate design, as presented earlier, the monthly customer charge was $5 and the volumetric charge was $1.50 per Mcf)
- One outcome would be that low-usage customers would face higher gas bills and high-usage customers would face lower gas bills, compared to the standard rate design; for example, a customer consuming 30 Mcf per year would see the annual non-gas portion of her bill increase from $105 to $182; for a customer consuming 120 Mcf, his bill would drop from $240 to $202

SFV: Better than RD?

Advantages	Disadvantages
More compatible with efficient-pricing principles	Adverse effect on low-usage customers, many of whom may be low income
More flexibility to a utility in competing with alternative fuel providers	Reduced incentives for customer-initiated energy efficiency
Elimination of intra-class subsidies	Possible appreciable increase in summer gas bills and bills to some low-usage customers
Simpler to implement and for customers to understand	Likely stronger opposition from stakeholders and commission staff
How many capital-intensive services are priced	
Non-tracker with no periodic true-up or price changes between rate cases	
More stable gas bills from (say) weather fluctuations	
More evenly allocates the recovery of fixed costs across seasons	

Earnings Sharing Mechanism

- The utility adjusts its rates periodically (e.g., annually) when its actual return on equity falls outside some specified band
- If the band encompasses a 10-14 percent rate of return on equity, when the actual return is 9 percent the utility could adjust its rates upward to increase its return closer to 10 percent
- This mechanism helps to stabilize a utility's rate of return without a formal rate case review
- This mechanism should reduce the frequency of future rate cases and allow adjusted rates to coincide closer to recent market developments, including those affecting a utility's costs

Earnings Sharing -- *continued*

(1) $\boldsymbol{ROE_{retained} = ROE_{earned}}$

(when ROE_{earned} lies within the specified “dead band” region)

<u>otherwise</u>

(2) $\mathbf{ROE_{retained} = ROE_{end} + g(ROE_{earned} - ROE_{end})}$

(where ROE_{end} is an end point of the “dead band” region and “g” equals the sharing ratio)

Earnings Sharing -- *continued*

- <u>Numerical example</u>
  - Assume that the “dead band” region is 10-14% rate of return on equity (with 12% estimated as the utility’s cost of equity)
  - Assume also that the sharing ratio (“g”) is 0.5
  - During the year, assume that the utility earned a 16% rate of return on equity
  - Under the mechanism, the utility would rebate to customers an amount equivalent to 1 percentage point of its ROE out of the 2 percentage points it earned beyond the upper end of the “dead band” region (14%)
  - Thus, the utility’s adjusted ROE would be 15% (14% + 0.5[16% - 14%])

Earnings Sharing -- *continued*

- Questions and Issues
  - What benefits does an earning's sharing mechanism have over traditional ratemaking?
  - What incentives does a utility have under the earnings-sharing mechanism to control costs?
  - Should the sharing component be constant? Would other than a 50/50 sharing ratio be preferable?
  - Is a "dead band" needed? If so, how large should it be?
  - How does the mechanism help (1) protect the utility from declining consumption per customer and (2) achieve revenue stabilization?

Cost-Based Customer Charge

- Customer costs include those costs associated with serving customers, irrespective of the amount or rate of gas usage; these costs include operating and capital costs that vary directly with the number of customers
- One issue in recent rate cases is whether a utility should raise the customer charge in line with customer costs; according to cost-of-service studies, most gas utilities have customer charges set below marginal customer costs
- Increasing the customer charge would improve economic efficiency, since the volumetric or usage charge would better reflect a utility's variable or marginal cost
- A higher customer charge would tend to increase summer gas bills and reduce winter bills, as well as mitigate the effect of weather on customer bills
- On the downside, a higher customer charge could harm low-usage customers and meet with public disapproval (which it has), especially for increasing minimum summer gas bills

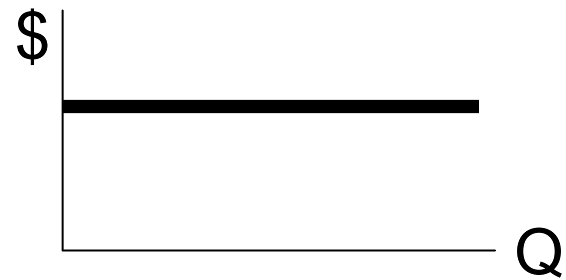
Declining-Block Rate

- The customer pays a lower rate for gas consumed at successively higher blocks
- As an illustration, the customer would pay \$5.50 per Mcf for the first 100 Mcf, and \$4.50 for all consumption over 100 Mcf
- This rate structure promotes the sale of gas by lowering the marginal price to high-usage customers from additional consumption
- A utility's earnings become more stable when the recovery of fixed costs occurs in the low-usage blocks, where customers will inevitably consume at the minimum
- This rate structure promotes economic efficiency when the price at higher usage blocks, within which customers use gas, corresponds to variable or marginal cost; when marginal cost does not decline with higher levels of consumption, this rate structure is discriminatory in favoring larger users
- By encouraging sales, this rate structure would tend to improve system utilization (i.e., the ratio of average demand to system capacity, defined over a specific time)

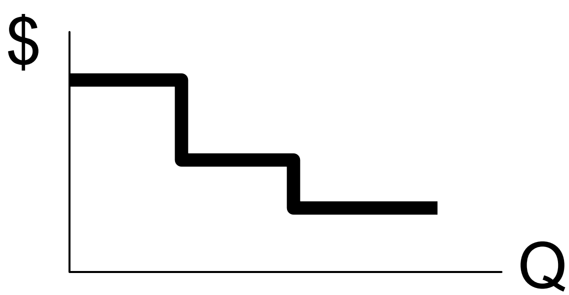
Examples of Rate Designs: Conflicts in Objectives

Flat Bill per period, no usage charge

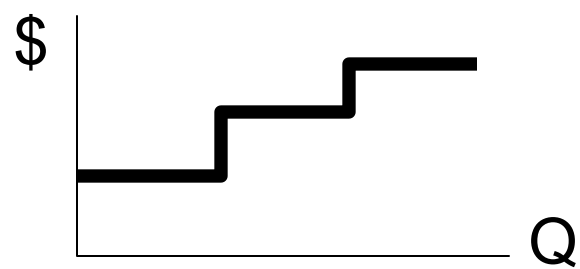
Uniform: Flat Rate per unit



Declining Block



Inverted Block



Bonbright's Eight Criteria for Ratemaking: The Guide for PUCs

- Simplicity, understandability, public acceptability and feasibility of implementation
- Uncontroversial as to proper interpretation
- Effectiveness in providing the utility with adequate revenues to recover costs
- Year-to-year revenue stability
- Rate stability
- Fairness among customer classes
- Avoidance of undue price discrimination
- Economically efficient in giving customers proper price signals, for example, in not over-consuming utility service

Affordability Issues for Low-Income Customers and Implications for Gas Utilities

Energy Burden on Poor Households

- Low-Income Home Energy Assistance Program (LIHEAP) recipients typically spend 20% of their annual income on home energy bills – more than 6 times the percentage that other income groups spend on home energy use
- Increases in energy prices since 1998 have far exceeded any growth in LIHEAP recipients' income, leaving less money for food, rent and health care
- About 15% of eligible households receive LIHEAP assistance
- LIHEAP funds haven't kept pace with the increase in the number of households eligible for funds

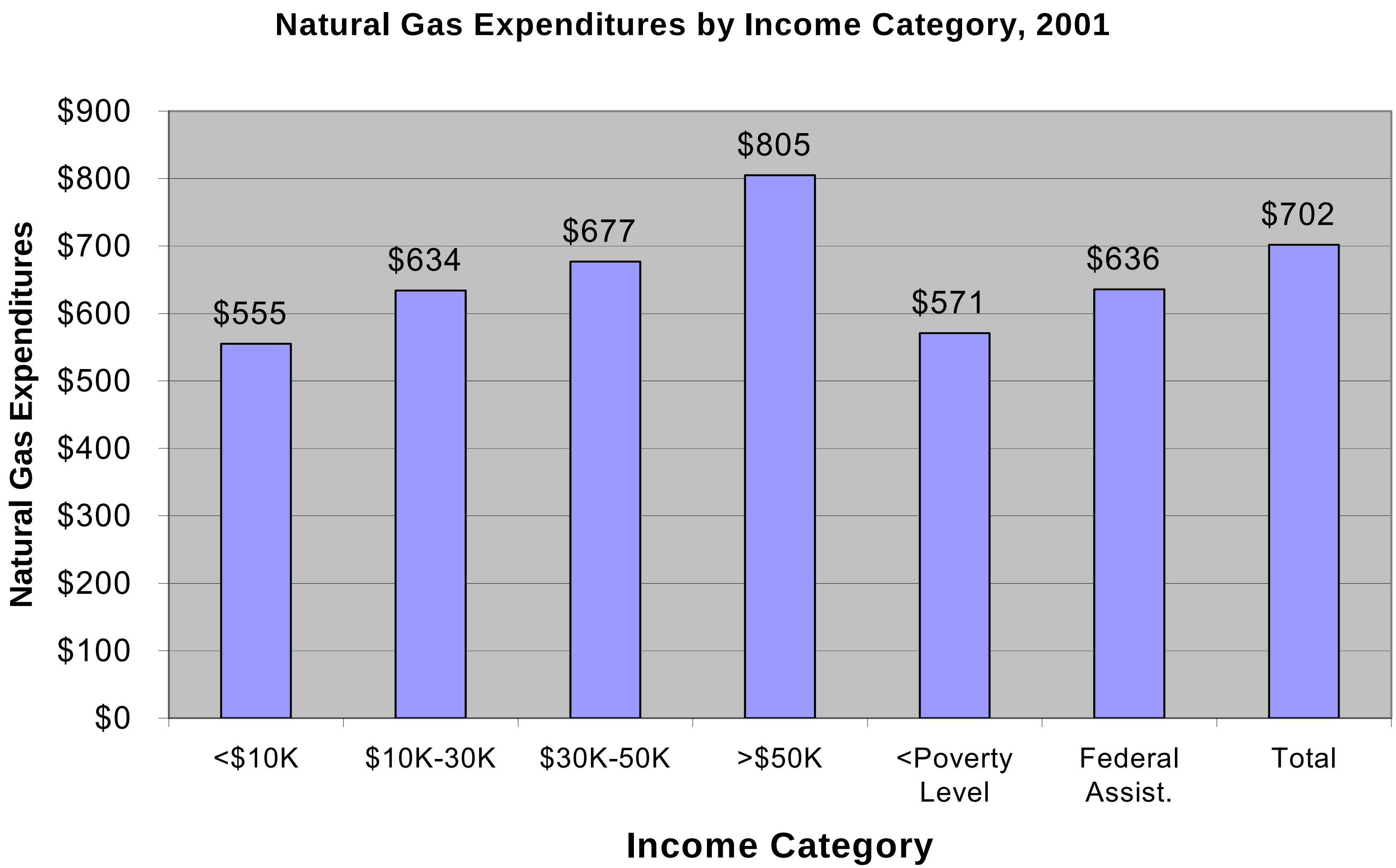
Energy Costs by Income, 2004

(source: Bureau of Labor Statistics)

Income	Energy Costs*	% of Budget
< $5K	$1,460	28%+
$5K-9.99K	$1,554	15-31%
$10K-14.99K	$1,954	13-20%
$15K-19.99K	$2,215	11-15%
$20K-29.99K	$2,556	9-13%
$30K-39.99K	$2,905	7-10%
$40K-49.99K	$3,231	6-8%
$50K-69.99K	$3,689	5-7%
>$70K	$4,645	≤7%

* Annual spending on gasoline, motor oil, natural gas, electricity, fuel oil and other fuels

Natural Gas Expenditures by Income Category, 2001



Utility Energy Assistance Programs (2006 Industry Survey of More Than 100 Gas Utilities)

- *Rate discounts* (account for 78% of total utility assistance) (45% of gas utilities offer)
- *Waivers on customer charges, reconnection fees, late charges, or deposit fees* (8% of total utility assistance)
- *Arrearage forgiveness* (forgive portion of or all of past due amount of qualified customer) (3% of total utility assistance) (35% of gas utilities offer)
- *Energy efficiency/weatherization programs* (11% of total utility assistance)
- *Shareholder contributions* to assist low-income households (50% of gas utilities offer)

Energy Assistance to Low-Income Households (2006)

- LIHEAP ($3.2 billion)
- State and local ($739 million)
- Utility ($1.8 billion)
- Fuel fund ($103 million)
- Other ($60 million)
- Total **($5.9 billion)**

Ways in Which Energy Assistance Programs Can Be Deficient

- Wasteful in not providing the maximum benefits to recipients per dollar of subsidy provided by society
- Recipients sometimes include the non-needy (e.g., lifeline rates)
- Inadequate funding, reflected by the large number of low-income households whose utility service is terminated
- Economically inefficient in that recipients are induced to consume additional energy because of below-cost prices at the margin
- Some don’t really address the severity of low-income households’ financial distress, where, unless given large assistance, these households still would have to cut back on other essentials (e.g., budget billing plan)

Collections Survey (2007 NRRI Analysis)

- Past due residential accounts (i.e., customers in arrearage) relative to total accounts increased for gas customers from 16.5% in 2001 to 21% in 2006, and the total amount of uncollectible expenses rose 39% between 2003 and 2006, indicating that customers faced increased difficulty in paying their home energy bills
- Some state commissions reported especially high arrearages. For example, as of May 1, 2006, four states showed the average arrearage of gas customers at over $500, with one state's average arrearage at $970. During the period from October 2005 to May 2006, the average arrearage for gas utilities ranged from $220 to $340
- For 2005, terminations as a percentage of total residential accounts were 5.5 per cent for gas utilities
- Gross-write-offs as a percentage of residential billings, for 2005, were 2.1 percent for gas utilities
- The evidence indicates that the most serious problem lies with customers accumulating large arrearages on their gas bills during the winter heating season; survey responses showed that during the winter of 2005-2006 the average arrearage of gas utilities grew by about 50 percent; an earlier survey showed that arrearage accumulation over the winter of 2001-2002 grew by less than 12 percent

Mean Percentage of Residential Accounts Past Due

Date/Type of Utility	Electric	Gas	Combination
10/1/2001	21.0%	16.5%	19.0%
4/1/2002	20.7	19.1	18.1
3/31/2004	18.5	19.2	15.4
10/1/2005	21.1	18.5	12.4
5/1/2006	21.5	21.0	15.6

Average Arrearage (in dollars)

Date/Type of Utility	Electric	Gas	Combination
10/1/2001	$120.33	$263.30	$166.70
4/1/2002	135.70	227.23	159.03
3/31/2004	159.65	226.49	240.11
10/1/2005	162.01	217.35	227.65
5/1/2006	159.59	333.61	276.58

Terminations as a Percentage of Total Residential Accounts (Mean Value)

Date/Type of Utility	Electric	Gas	Combination
2001	4.7%	3.5%	3.7%
2002	5.2	4.4	5.1
2004	5.2	5.0	4.1
2005	4.6	5.5	4.5

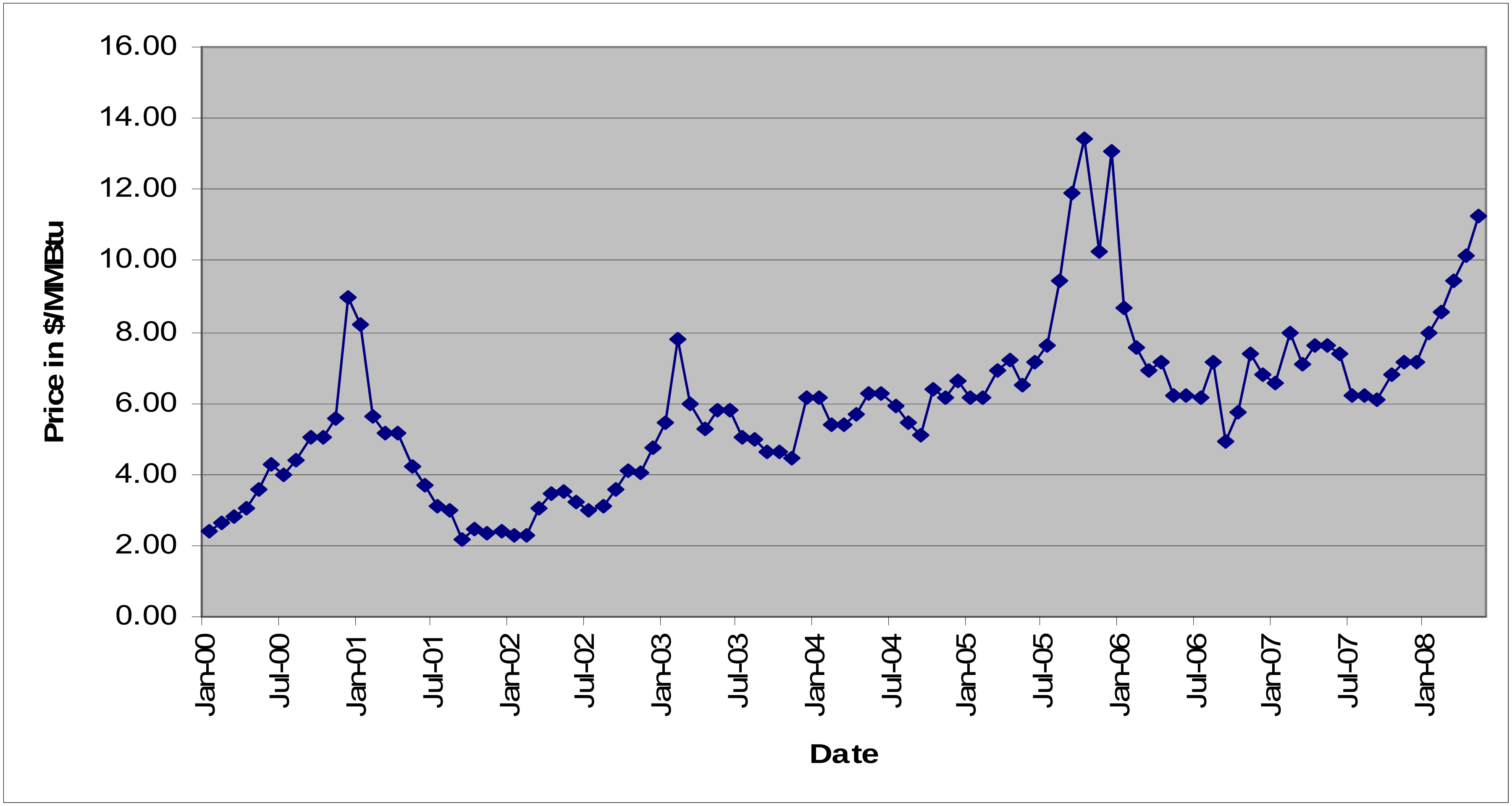
Recovery of Bad Debt

- Standard method: the adjustment of test-year base revenues for bad debt
- Recent proposals: bad debt tracker, for example, where the utility recovers all or a portion of its bad debt not already included in base rates without filing for a new rate case (e.g., gas-cost portion of bad debt expense is recovered through the purchased gas adjustment [PGA])

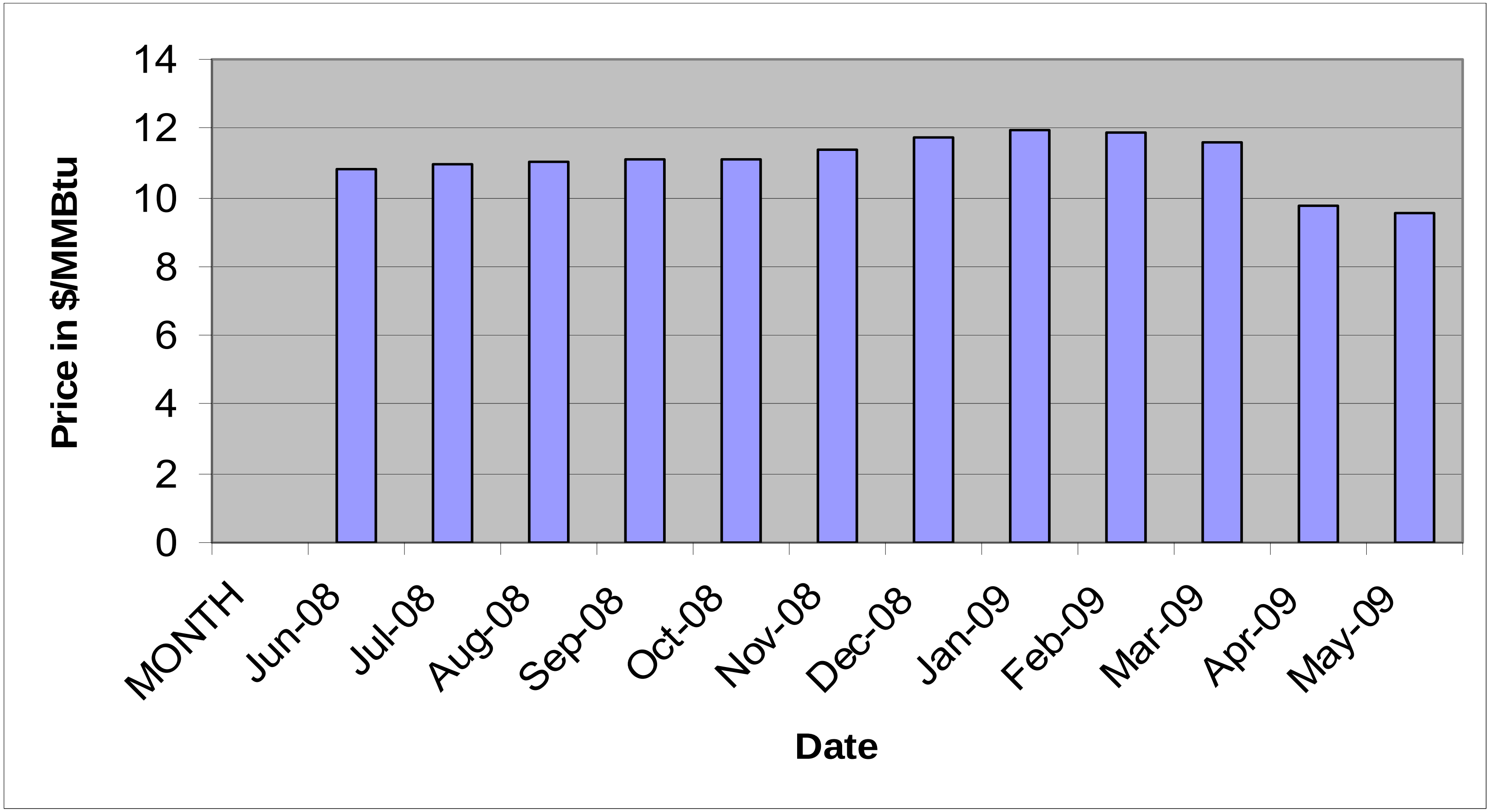
- *Problems with the standard method, as argued by some gas utilities*: the practice of recovering bad debt as a fixed expense in base rates is no longer appropriate because it does not account for the dramatic increase in bad debt over the past several years because of the combination of high gas commodity prices and more customers falling further behind in paying their gas bills

Projections of the U.S. Natural Gas Market

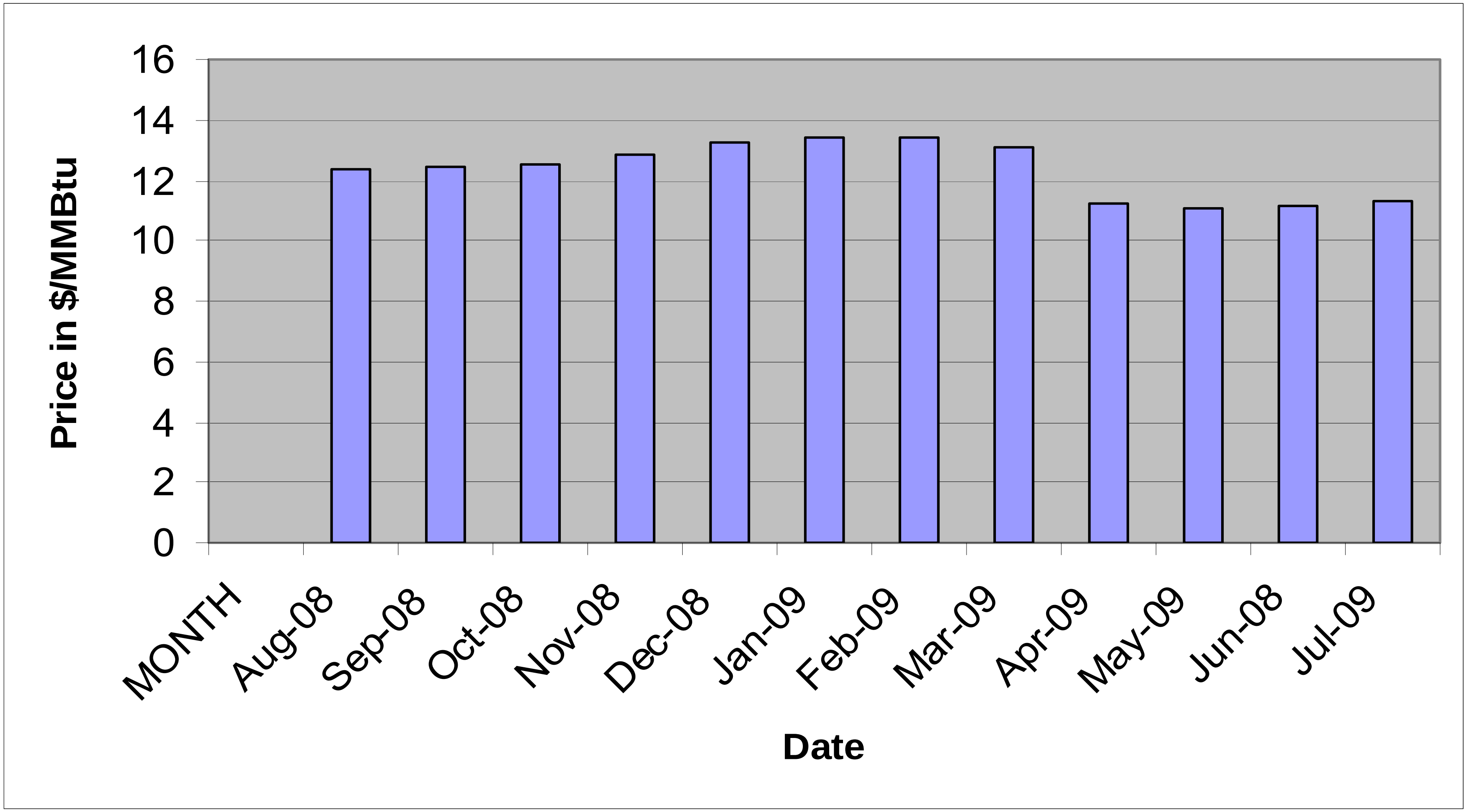
Henry Hub Prices, January 2000-May 2008



NYMEX Futures Prices, as of April 29, 2008



NYMEX Futures Prices, as of July 8, 2008



EIA's Short-Term Projections, as of July 2008

- **Average wellhead price:** $10.20 per Mcf in 2008, and $10.47 in 2009 (the 2007 price was $6.39)
- **Consumer prices:** residential prices projected to be 16.2% higher in 2008 than in 2007, and then increase by a further 16% in 2009
- **Consumption:** demand projected to increase by 2.1% in 2008 and 1.1% in 2009
- **Supply:** moderate growth in 2008
  - As of the end of June, working gas in storage about 15% below the level at that time last year, and over 2% below the 5-year average
  - Domestic production projected to increase by over 8% between 2007 and 2009
  - LNG imports projected to decrease by almost 38% in 2008 and then rebound in 2009

EIA's 2008 and 2009 Projections: Changes over April-July

	2007	2008	2009
LNG Imports (Bcf)	770	680 (A), 582 (M) 530 (JN) 480 (JL)	949 (A) 894 (M) 850 (JN) 790 (JL)
Average Wellhead Price ($/Mcf)	$6.39	$7.56 $8.64 $9.82 $10.20	$7.42 $8.52 $9.96 $10.47
Average Henry Hub Price ($/Mcf)	$7.17	$8.59 $9.69 $11.05 $11.86	$8.32 $9.41 $10.99 $11.62
Residential Gas Price ($/Mcf)	$13.00	$13.83 $14.40 $14.84 $15.11	$14.15 $15.35 $16.92 $17.46

Long-Term Gas Outlook: Comparison with 2007 Projections (source: EIA, *AEO 2008*)

- Higher natural gas price projections (higher oil prices and increase in production costs associated with recent trends)
- Slower projected growth in natural gas consumption because of lower economic growth, higher prices, slower growth in electricity demand, greater use of more efficient appliances and slower growth in energy-intensive industries
- Less optimistic on LNG imports
- Higher delivered price because of increased margins from declining use per customer

Highlights of *AEO 2008*

- Starting around 2016, total gas consumption will begin to fall, particularly in the electricity and industrial sectors (total gas consumption increasing from 21.7 Tcf in 2006 to 23.8 Tcf in 2016, then declining to 22.7 Tcf by 2030)
- Slow increase in domestic gas production
- Future direction of global LNG market is a key uncertainty (price and availability of LNG in the U.S. market uncertain because of many new international players entering LNG markets and strong competition for available supply) (U.S. LNG regasification capacity will nearly quadruple by 2009, but considerably less LNG supply is expected to be available)

Highlights of *AEO 2008* -- *continued*

- Prices will dampen as new supplies enter the market (prices are projected to decline, in real dollars, until around 2016 as new gas supplies enter the U.S. market)
- Alaskan gas pipeline expected to be completed in 2020
- Sharp drop in conventional onshore gas production, with offshore production peaking in 2017 as new resources come online in the Gulf of Mexico

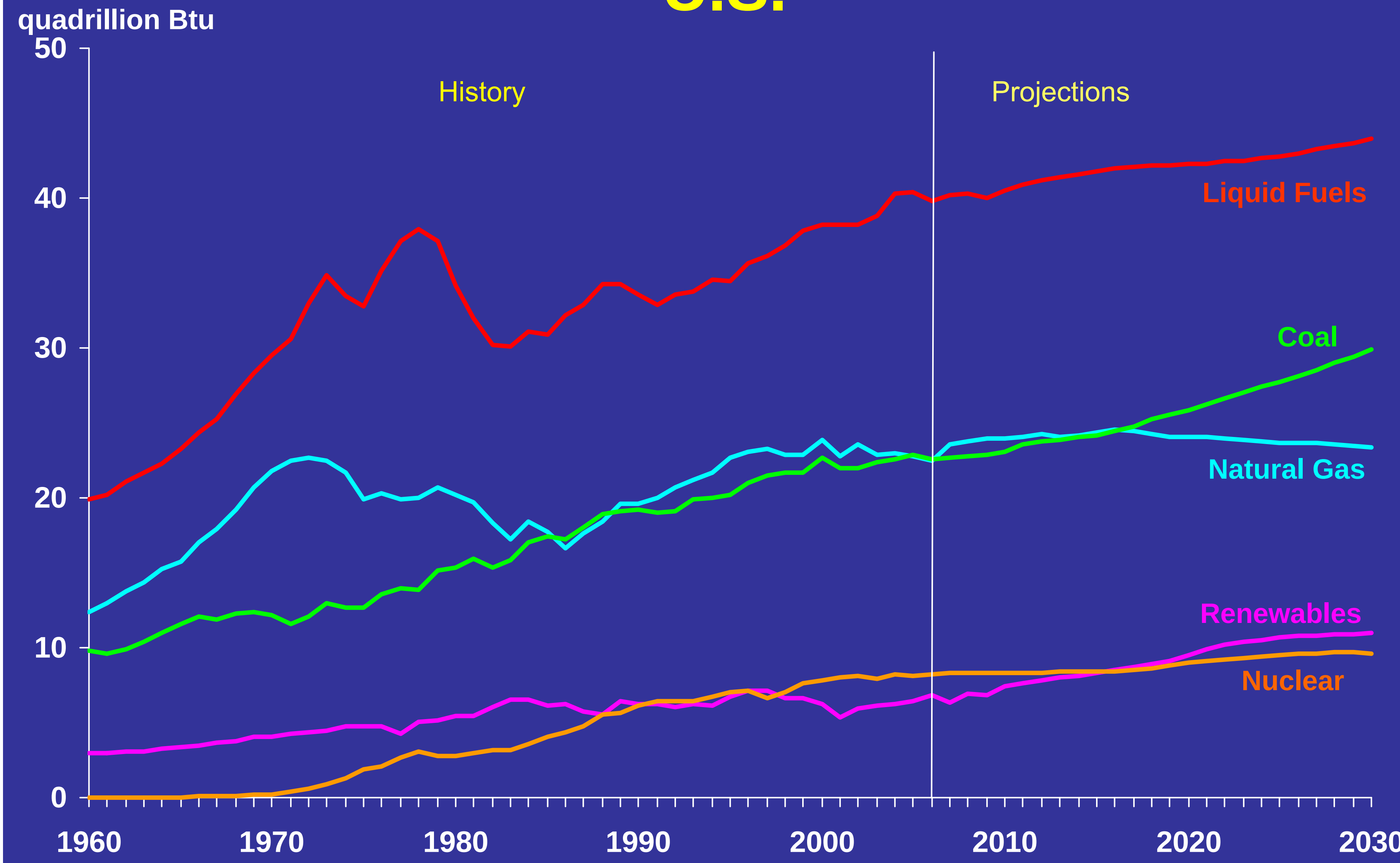
Highlights of *AEO 2008* -- *continued*

- Production of unconventional gas, particularly gas from shale, is expected to be a key contributor to growth in U.S. gas supplies
- Net pipeline imports of gas into the U.S. expected to fall from 2.9 Tcf in 2006 to 0.3 Tcf in 2030, because of both resource depletion in Alberta and Canada's growing domestic demand

Natural Gas Wellhead Price Projections (in constant dollars)

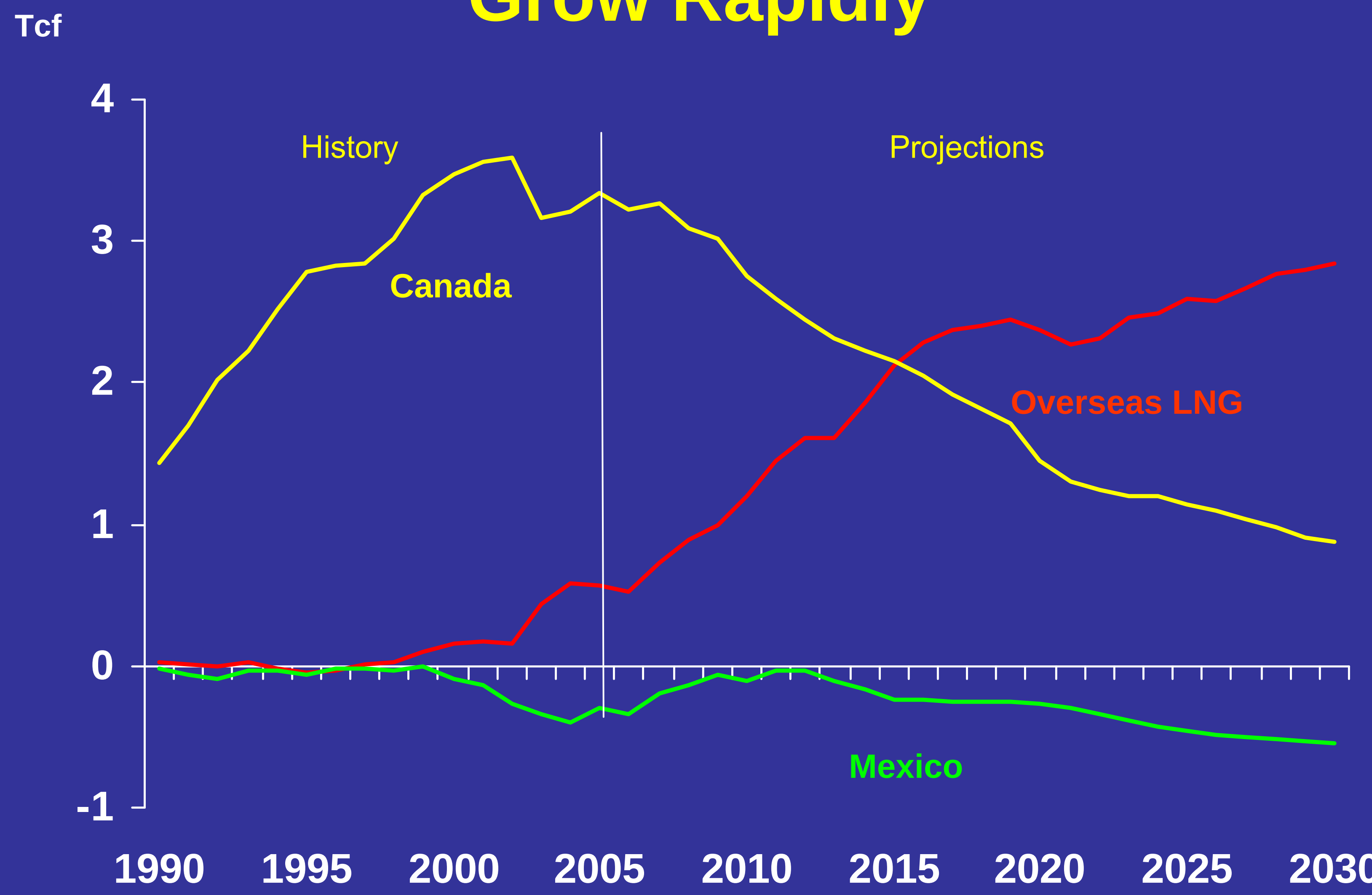
Annual Energy Outlook 2008

Consumption of Different Fuel Sources in the U.S.



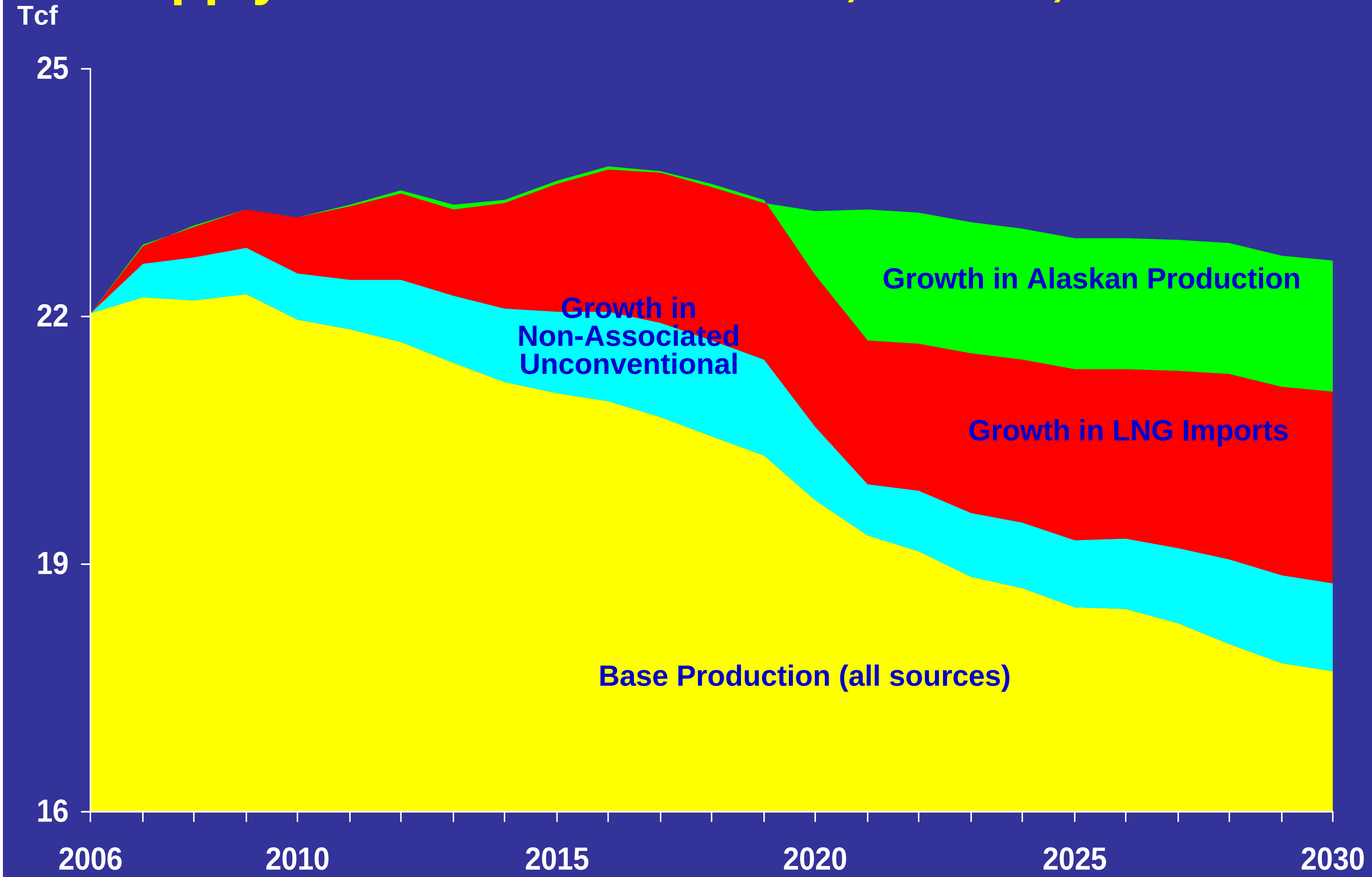
Annual Energy Outlook 2008

Canadian Imports Decline and LNG Imports Grow Rapidly



Annual Energy Outlook 2008

The Major Sources of Incremental U.S. Natural Gas Supply: Unconventional Gas, Alaska, and LNG



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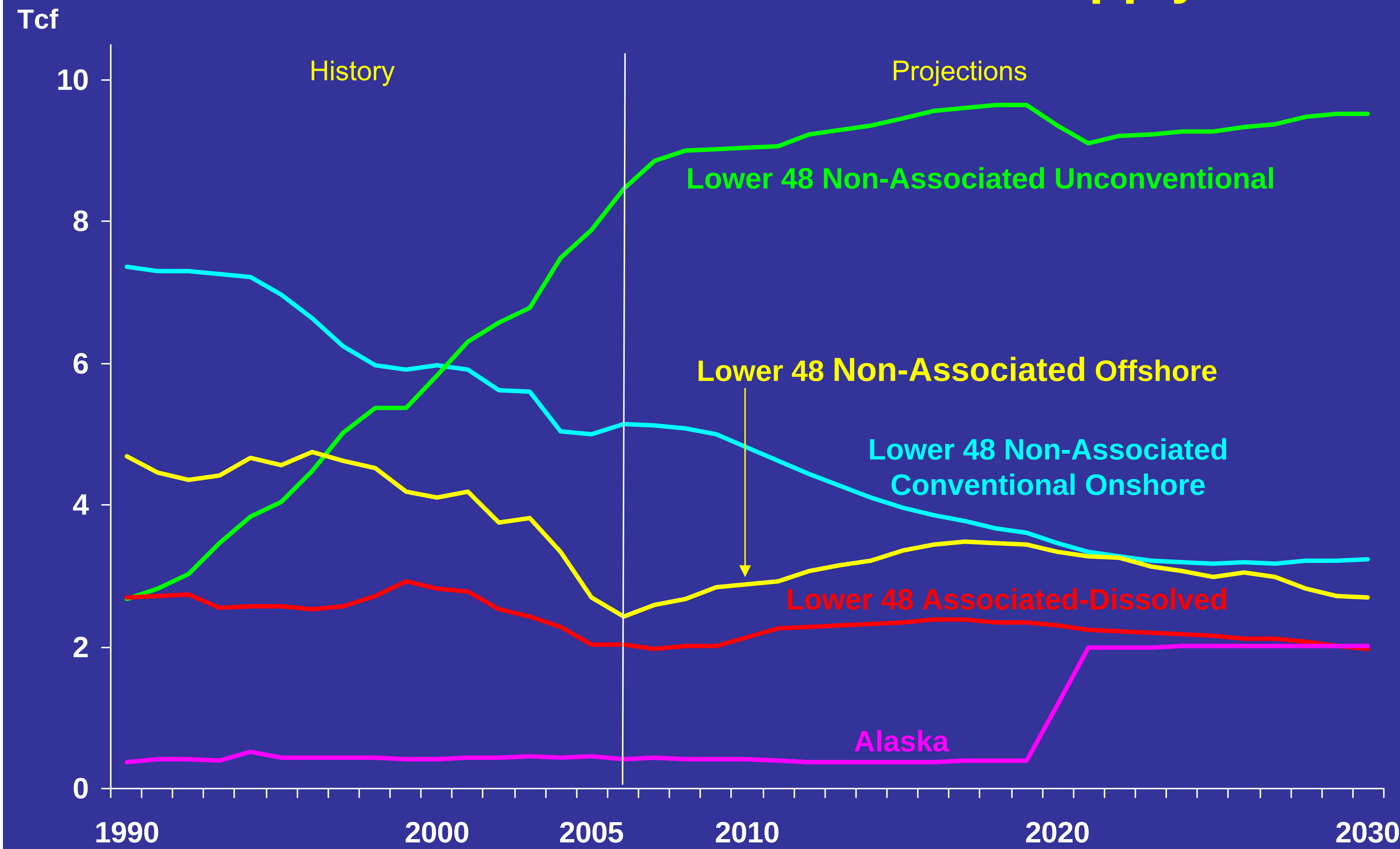
Unconventional Natural Gas Production Will Account for More of Domestic Supply



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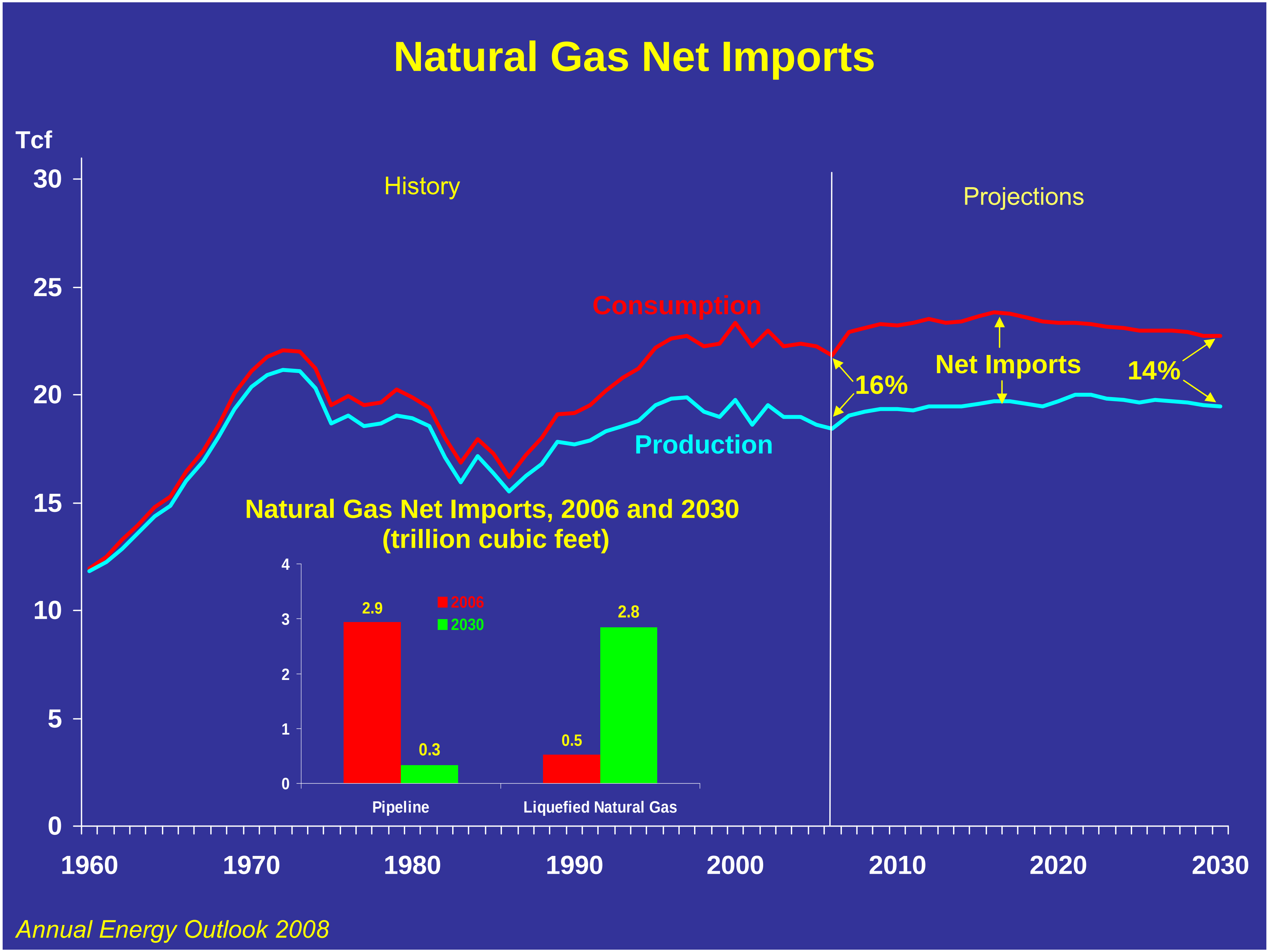
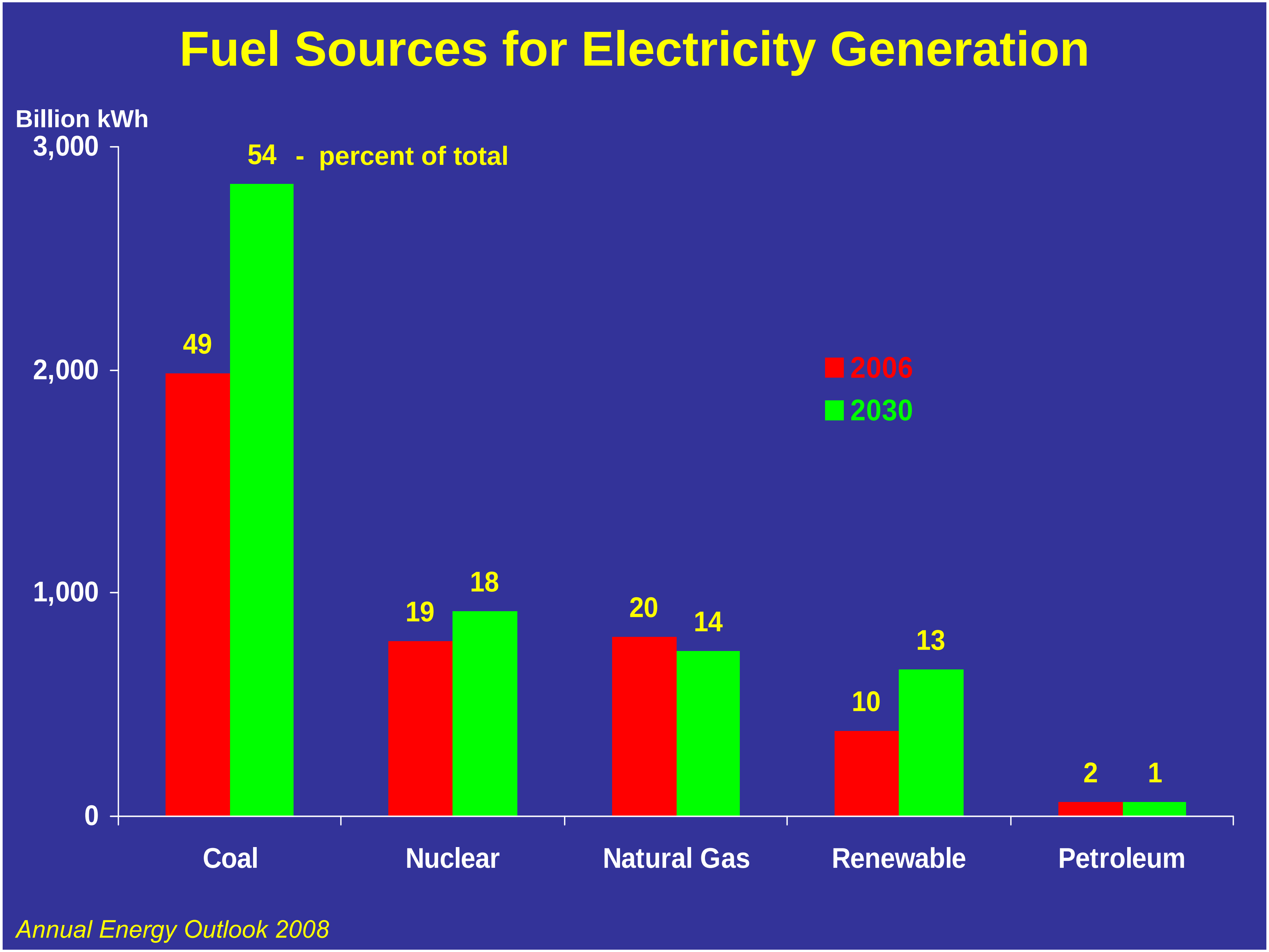
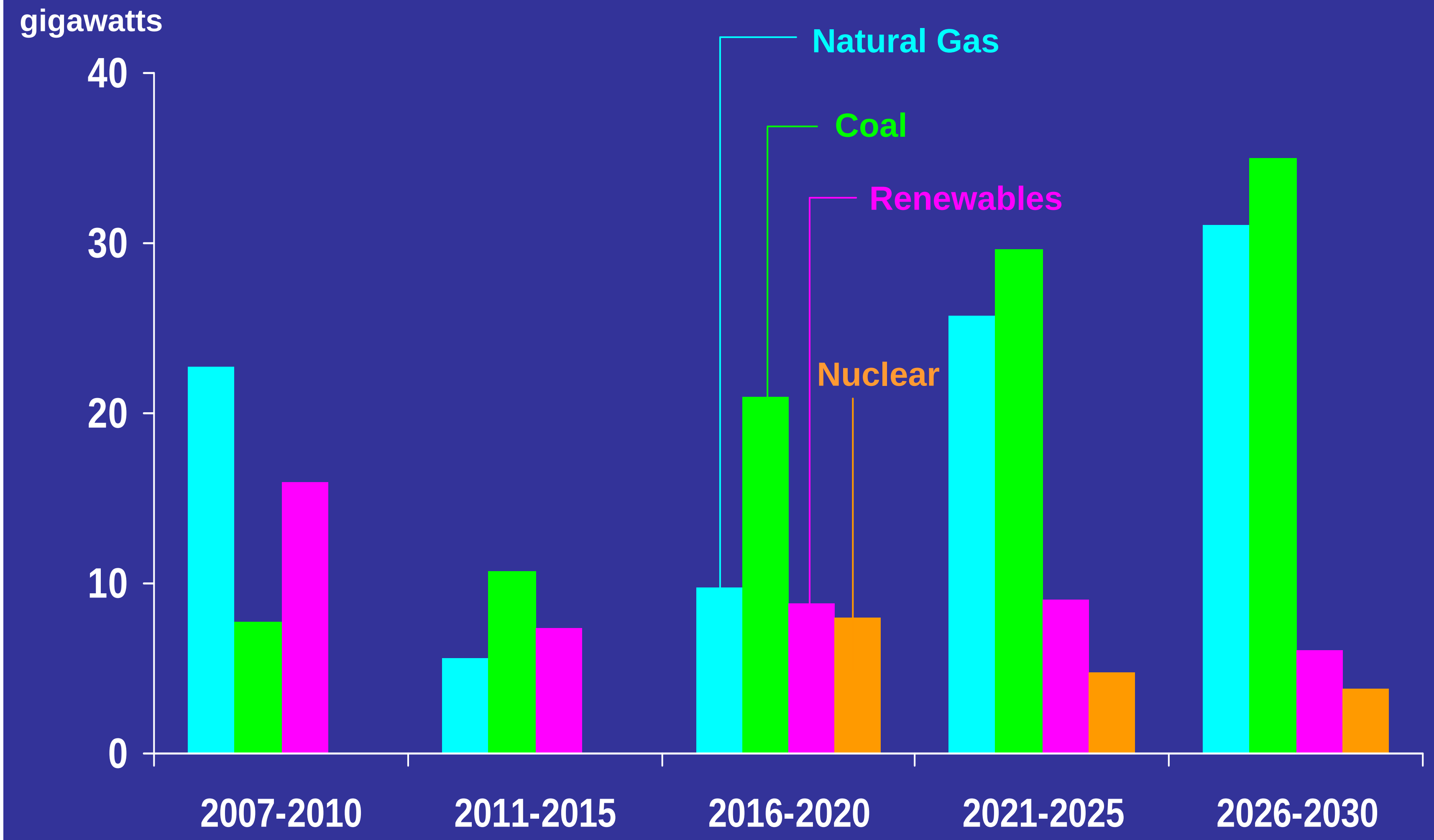

Natural Gas Net Imports
Tcf
30
25
20
15
10
5
0
History
Projections
Consumption
Production
Net Imports
16%
14%
1960
1970
1980
1990
2000
2010
2020
2030
Natural Gas Net Imports, 2006 and 2030
(trillion cubic feet)
4
3
2
1
0
2006
2030
2.9
0.3
0.5
2.8
Pipeline
Liquefied Natural Gas
Annual Energy Outlook 2008


Fuel Sources for Electricity Generation
Billion kWh
3,000
2,000
1,000
0
54 - percent of total
49
19
18
20
14
10
13
2
1
2006
2030
Coal
Nuclear
Natural Gas
Renewable
Petroleum
Annual Energy Outlook 2008

Additional Generation Capacity thru 2030



Annual Energy Outlook 2008

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