



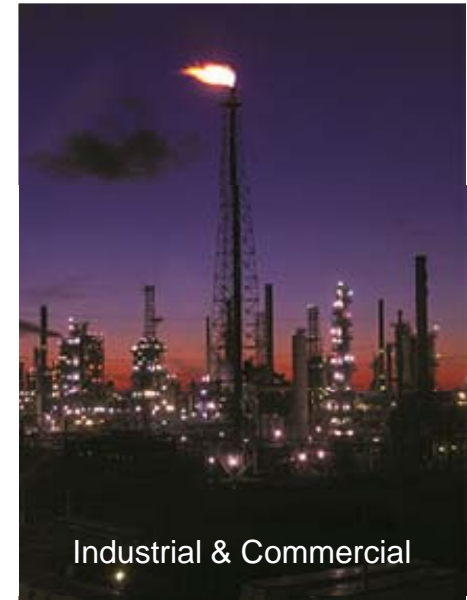
Power



Infrastructure



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Shale Gas Processing Retrofit Options



Ed Sheehan, P.E., P. Eng.
Kevin Taylor, P.E.
Johnny Johnson, P.E.

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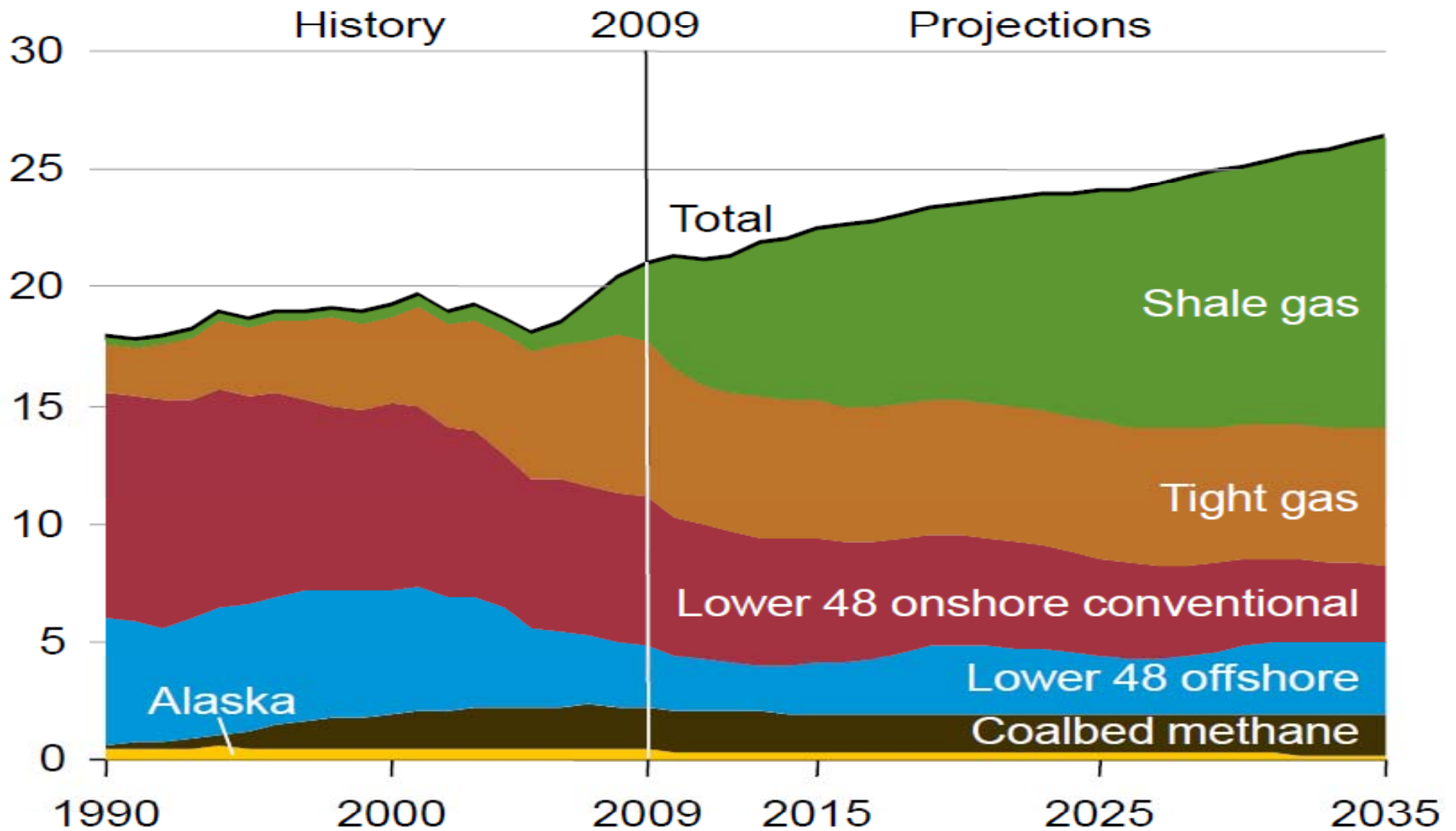
Shale Gas Processing Retrofit Options Overview

- **Introduction**
- **Shale Gas Outlook**
- **Overview Major Shale Developments**
- **Typical Sour Gas Plant configuration**
- **Shale Gas Impacts to a Typical Existing Gas Plant**
- **Possible Shale Gas Plant Configuration options**
- **Case Studies**



Shale Gas Outlook

U.S. Natural Gas Production by source, 1990-2035 (trillion cubic feet)



Source: US Energy Information Administration(EIA), Annual Energy Outlook 2011 with projections to 2035, page 79



Shale Gas Outlook

- **Shale Gas is estimated to be 47% of U.S. Natural gas Production by 2035.**
 - In 2009 Shale accounted for 16% of U.S. Natural Gas
 - Shale gas production grew by 17% from 2000 to 2006
 - Shale gas production has grown by 48% from 2006 to 2010
- **Estimate of technically recoverable unproved shale gas is as high as 827 trillion cubic feet**
- **Conventional onshore U.S lower 48 gas production drops by ~45% from 2009 to 2035.**
 - By 2035 approximately ~12% of natural gas supplies will be from Conventional onshore sources, versus ~30% in 2009.



Overview Major Shale Developments

U.S. Shale Gas Fields Locations and Gas Compositions

Field Name (Location)	Methane ⁽¹⁾	Ethane	Propane	CO ₂	N ₂	H ₂ S ⁽²⁾
Barnett (West Texas)	80.3	8.1	2.3	1.4	7.9	1-6ppm _v
	81.2	11.8	5.2	0.3	1.5	1-6ppm _v
	91.8	4.4	0.4	2.3	1.1	1-6ppm _v
	93.7	2.6	0.0	2.7	1.0	1-6ppm _v
Marcellus (New York, PA, Ohio, West Virginia)	79.4	16.1	4.0	0.1	0.4	>1 ppm _v
	82.1	14.0	3.5	0.1	0.3	>1 ppm _v
	83.8	12.0	3.0	0.9	0.3	>1 ppm _v
	95.5	3.0	1.0	0.3	0.2	>1 ppm _v
Fayetteville (Arkansas)	97.3	1.0	0.0	1.0	0.7	NR
New Albany (S. Illinois Indiana, Kentucky)	87.7	1.7	2.5	8.1	NR	NR
	88.0	0.8	0.8	10.4	NR	NR
	91.0	1.0	0.6	7.4	NR	NR
	92.8	1.0	0.6	5.6	NR	NR
Antrim (Michigan)	27.5	3.5	1.0	3.0	65.0	NR
	57.3	4.9	1.9	0.0	35.9	NR
	77.5	4.0	0.9	3.3	14.3	NR
	85.6	4.3	0.4	9.0	0.7	NR
Haynesville (N. Louisiana, East Texas)	95.0	0.1	0.0	4.8	0.1	5-20 ppm _v ⁽³⁾

Notes: 1. Compositions are normalized to 100%, 2. NR= Not Reported. 3. H₂S can be as high as 600 to 1000 ppm_v depending on location.



Overview Major Shale Developments

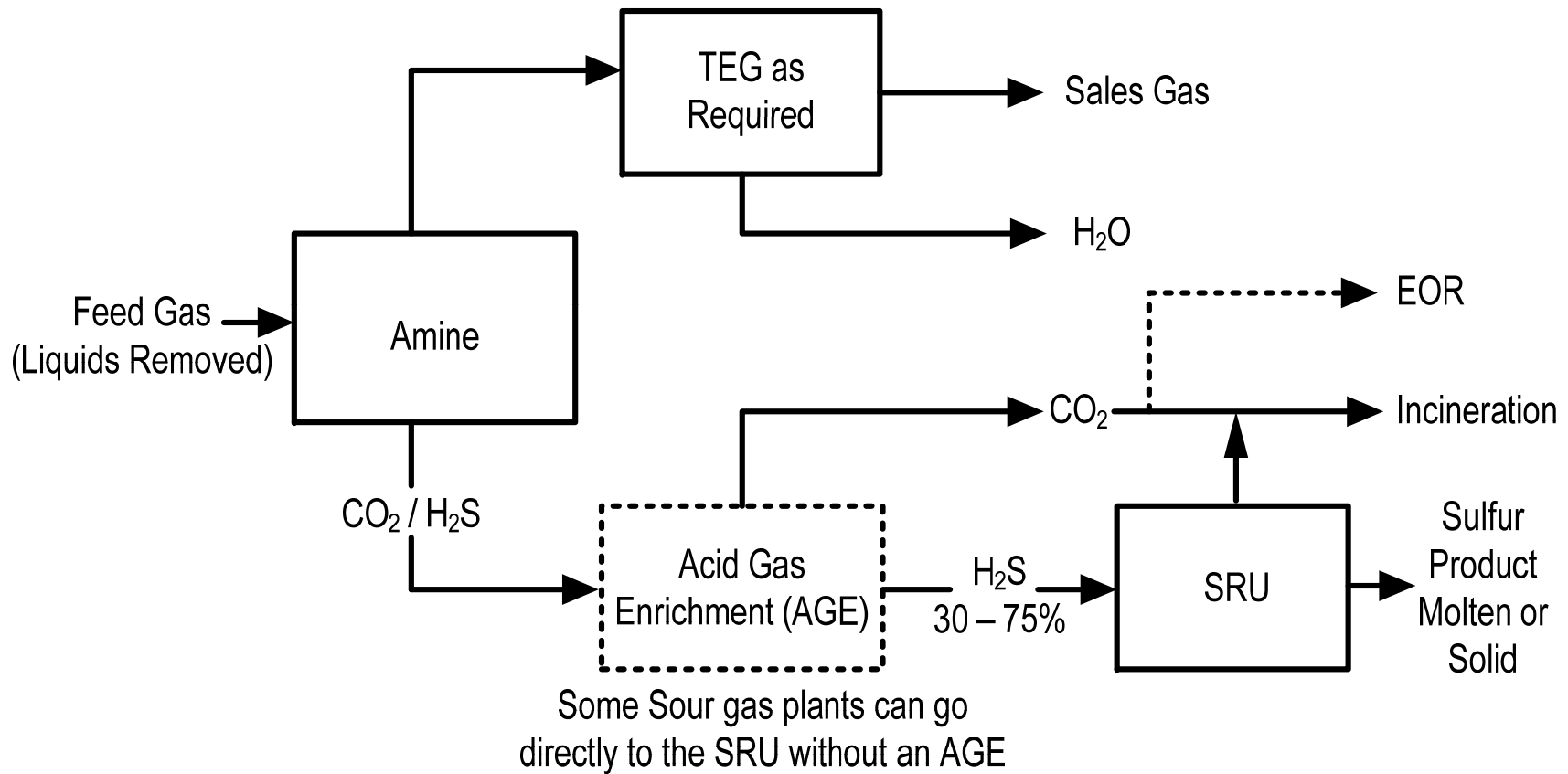
Canadian Shale Gas Fields Locations and Gas Compositions

Field Name (Location)	Methane	Ethane	Propane	CO ₂	N ₂	Other	H ₂ S (ppmv)
Horn River (N.E British Columbia/ N.W. Alberta)	88.1	0.1	0.01	11.0	0.74	0.04	100
	86.4	0.67	0.01	12.0	0.81	0.04	500
Montney (British Columbia / Alberta)	82.2	8.8	3.16	2.0	0.59	3.02	2,000 ⁽¹⁾

Note 1. Murphy Oil reports Montney shale gas has 1,000 ppmv H₂S.

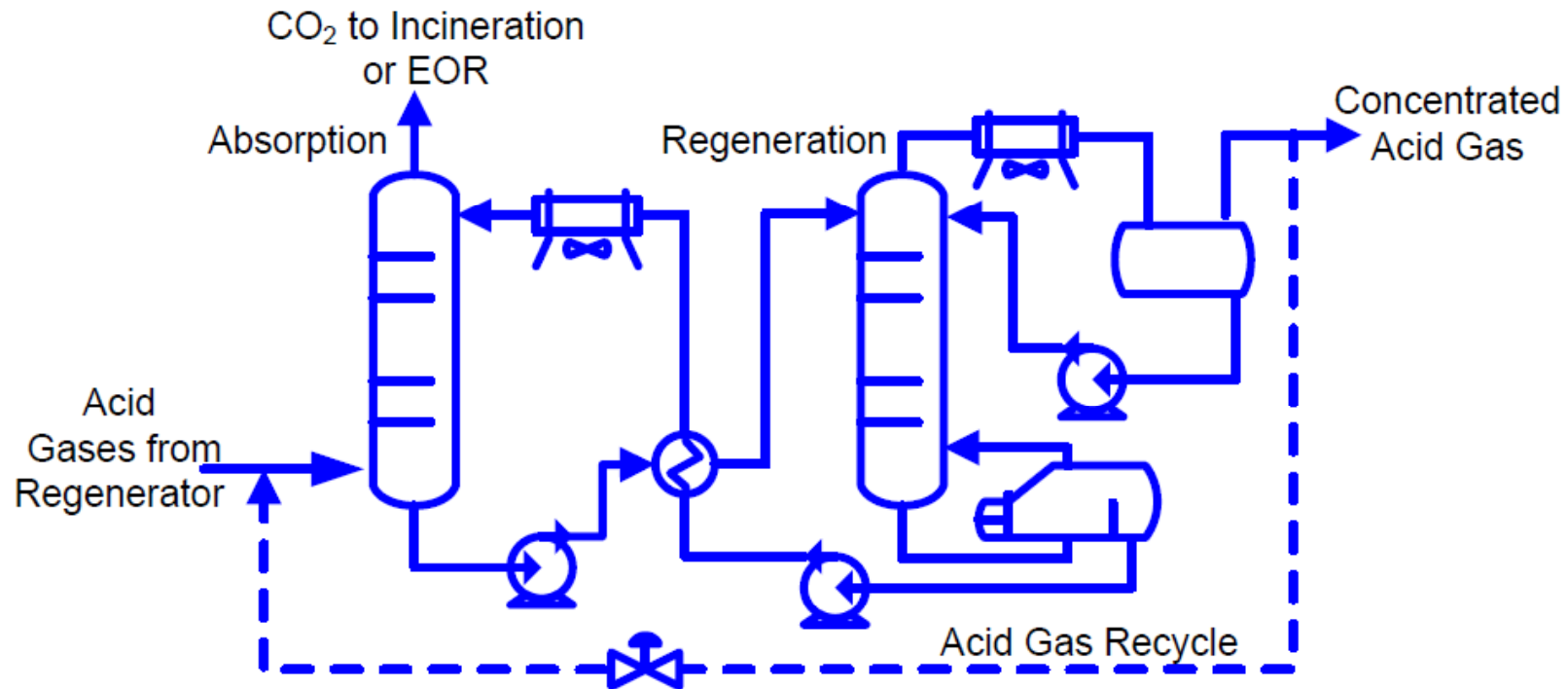


Typical Sour Gas Plant configuration



Shale Gas Impacts to a Typical Existing Gas Plant

- **Lowered H₂S concentration in Feed to Sulfur Recovery Unit (SRU)**
 - Dilution of the Acid Gas with additional CO₂
 - Reduced H₂S flow
 - AGE can help maintain SRU feed H₂S concentration requirements
 - AGE with URS SuperR Enrichment Configuration



Shale Gas Impacts to a Typical Existing Gas Plant

- Reduced Sulfur Recovery across the SRU

- Total Inlet Sulfur to SRU is reduced
- Equilibrium amount of elemental sulfur in the tail gas is unchanged

$$\% \text{ Sulfur Recovery} = 1 - (\text{Tail Gas Sulfur} / \text{SRU Feed Gas Sulfur})$$



- Overall mass of sulfur emitted may be significantly less than design or current environmental permit
- Additional Tail Gas clean-up possibly required



Shale Gas Impacts to a Typical Existing Gas Plant

- **Reduced Feed Rate to the SRU**
 - Turndown a consideration
 - At extremely low acid gas rates atmospheric heat loss will be a consideration
 - Possible new heat exchangers, tracing or heat panels may be required to maintain reactor temperature control and prevent solid sulfur from depositing
 - Plug tubes in waste heat boiler and sulfur condensers
 - Control valves may be oversized
- **New Sulfur handling or treating technology may be required**
 - New SRU
 - Acid Gas Injection
 - Other Technologies

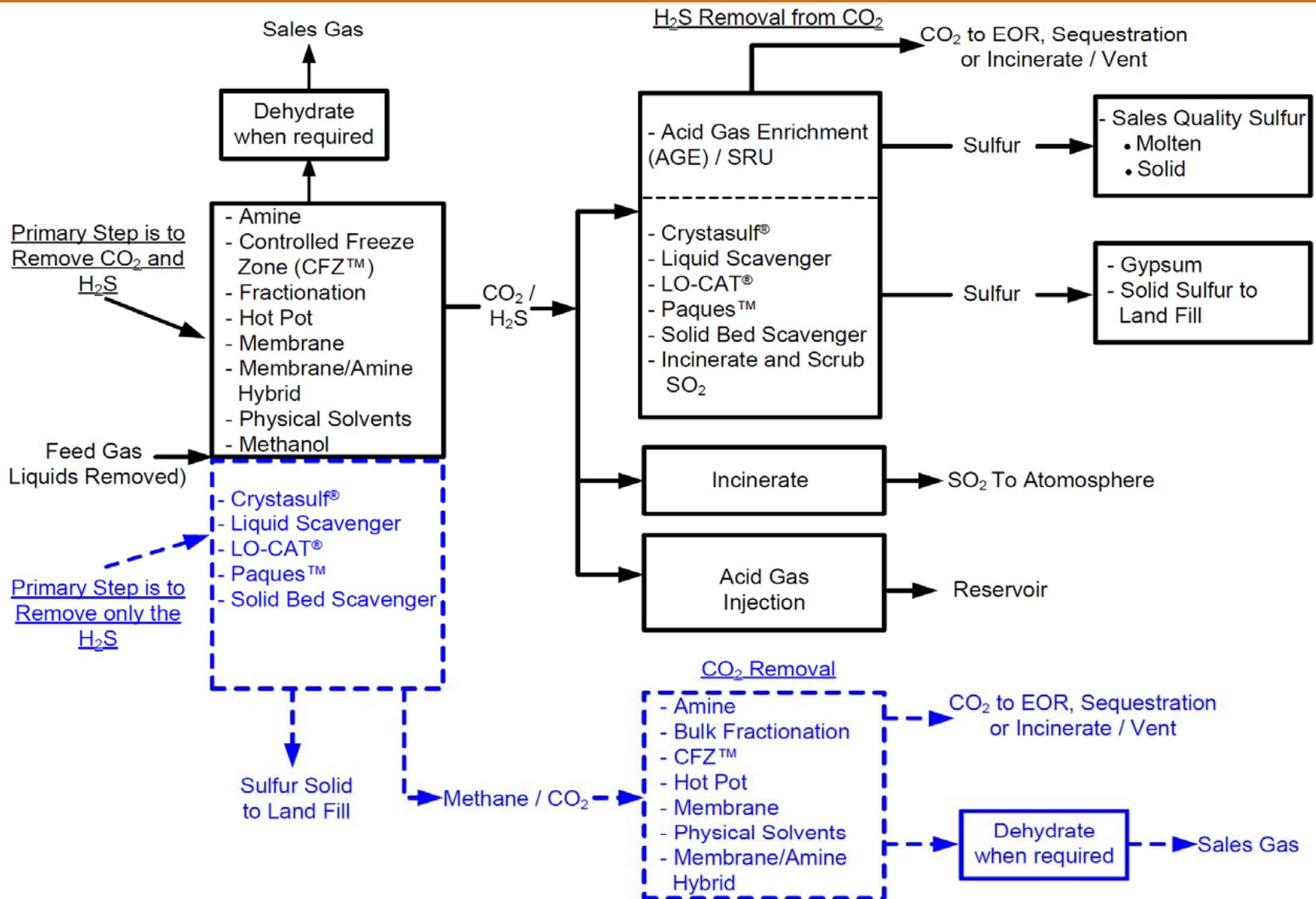


Possible Shale Gas Plant Configuration Options

- **Assume liquids removed upstream**
- **Primary Treating: CO₂ plus H₂S removal**
 - Secondary treating is on a Sour Acid Gas stream
 - Operating pressures are lower. Typical gas plant configuration
 - Most of processing equipment in the plant is sour
 - Dehydration is an exception.
- **Primary Treating: H₂S removal only**
 - Secondary treating is sweet, only removing CO₂
 - More of the plant's processing equipment is at high pressure
 - Sour portion of the plant limited to primary treating section



Possible Shale Gas Plant Configuration Options



Primary Treating - CO₂ and H₂S Removal

- Primary Treating Products

- Sales Gas that may or may not need to be dried
- Sour Acid Gas stream which will need Secondary Treating

- Primary Treating Technology Options

- Amine
- Bulk Fractionation
- Physical Solvents
- Membranes
- Hot Potassium Carbonate (Hot Pot)
- Methanol
- Controlled Freeze Zone (CFZ™)



Primary Treating - CO₂ and H₂S Removal

- Secondary Acid Gas Treating Options

- Typical configuration for acid gas derived from conventional gas
 - SRU with or without AGE
 - Incineration if H₂S level is low enough
 - Acid Gas Injection
 - Application limited by access to injection wells and ability to get permits



Primary Treating - CO₂ and H₂S Removal

- Secondary Acid Gas Treating Options (cont.)

- Possible Alternative Acid Gas Processing Options for Shale Gas with low H₂S
 - CrystaSulf®
 - Liquid or Solid Scavenger
 - LO-CAT®
 - Paques™
 - Incinerate and Scrub SO₂
- Typical Benefits to Alternative Acid Gas Options
 - Able to handle very low H₂S concentrations
 - Lower energy usage
 - Lower capital costs



Primary Treating - CO₂ and H₂S Removal

- **Secondary Acid Gas Treating Options (cont.)**
 - Typical Negatives to Alternative Acid Gas processing options
 - Solid Sulfur product is a waste to be land filled.
 - Technology not widely employed, less industry experience
 - Large make-up water requirements
 - Costly make-up chemical
 - New chemicals introduced into the plant that have to be safely handled.



Primary Treating - H₂S Removal Only

- **Primary Treating Products**
 - Solid Product Containing Sulfur
 - Methane/ CO₂ Stream that needs Secondary Treating.

- **Possible Primary Treating Options**
 - CrystaSulf[®]
 - Liquid or Solid Scavenger
 - LO-CAT[®]
 - Paques[™]



Primary Treating - H₂S Removal Only

- **Secondary Treating is CO₂ removal only**
 - Possible Treating Technology Options
 - Amine
 - Bulk Fractionation
 - Physical Solvents
 - Membranes
 - Hot Potassium Carbonate (Hot Pot)
 - Controlled Freeze Zone (CFZ™)
 - CO₂ is EOR Ready with Low H₂S
 - Incineration is likely required since residual methane and H₂S will be higher than can be vented directly to atmosphere.
 - Sales Gas may or may not need dehydration depending on Technology



Case Study Example – Basis

- Source Feed Gases

Components	Sour Feed Natural Gas (Mole %)	Shale Gas (Mole %)
Methane	89.8%	86.40%
Ethane	4.5%	0.75%
CO₂	4.1%	12.00%
N₂	0.2%	0.80%
H₂S	1.4%	0.05%
Total	100.0%	100.00%



Case Study Example – Basis

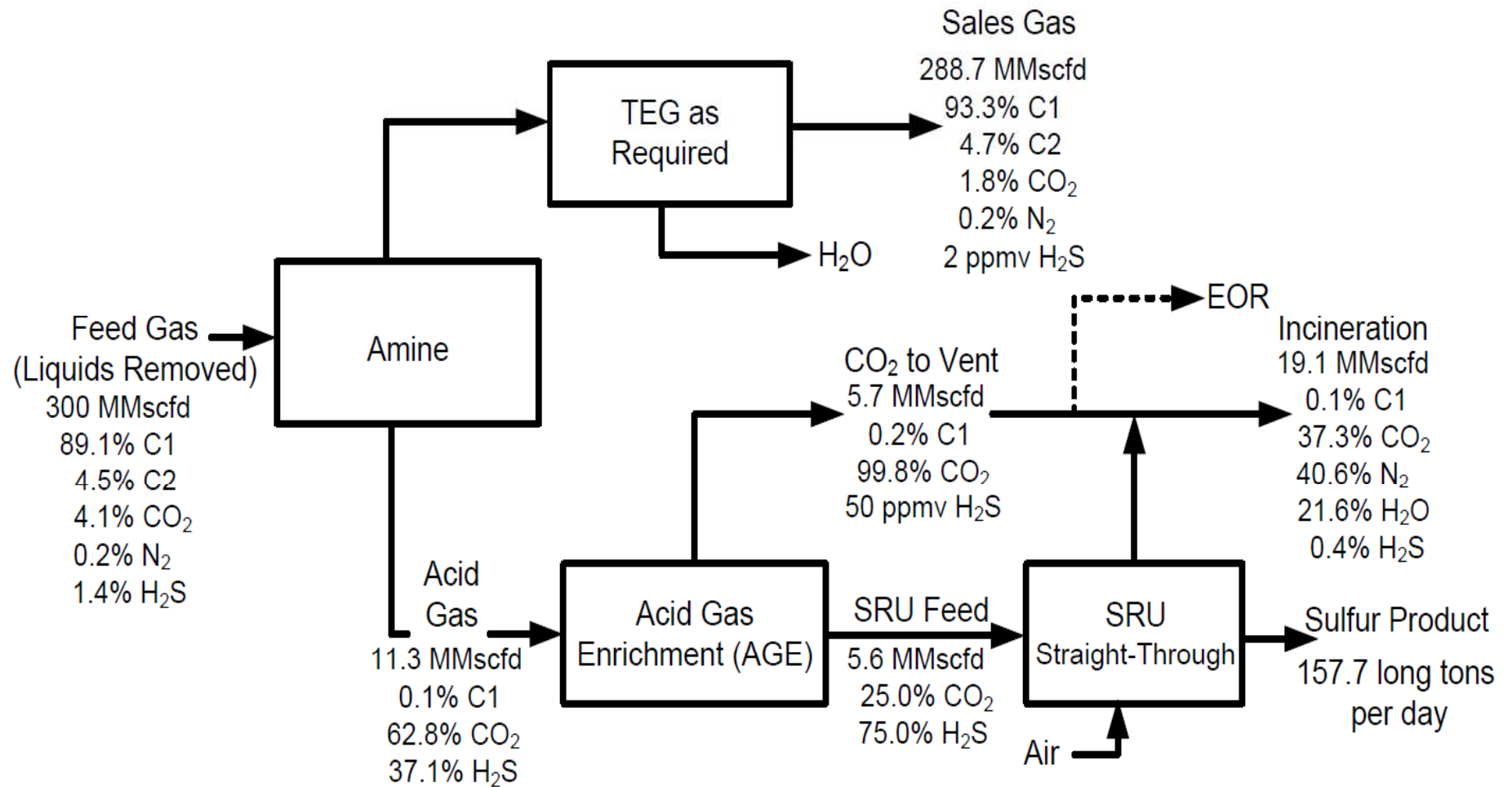
Feed, Intermediate and Product Composition assumptions

- Sales Gas composition
 - 1.8% CO₂
 - 2 ppm_v H₂S
 - Higher Heating Value (HHV) is minimum of 950 Btu/ SCF.
- Acid Gas
 - To AGE is specified at 1000 ppm_v methane.
 - To a straight-through SRU is specified at 75% H₂S,
 - To a split flow SRU is specified at 20% H₂S.
- H₂S content in the CO₂ stream from the AGE absorber is specified at 50 ppmv.
- Sulfur recovery across the SRU is specified at 98%.



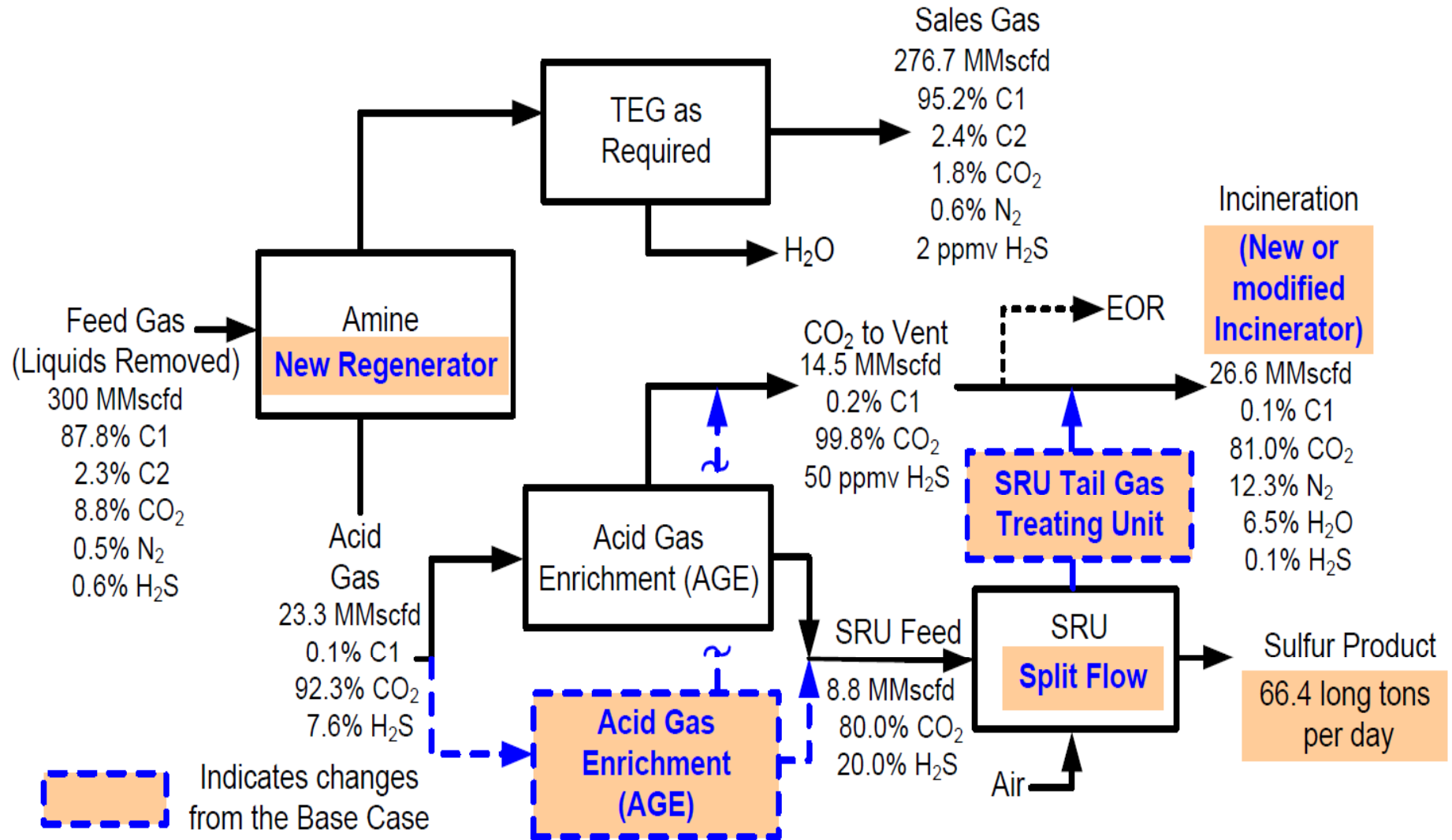
Case Study – Base Case

100% Sour Natural Gas / No Shale Gas



Case Study – Case One

40% Sour Natural Gas / 60% Shale Gas



Case Study – Case One

40% Sour Natural Gas / 60% Shale Gas

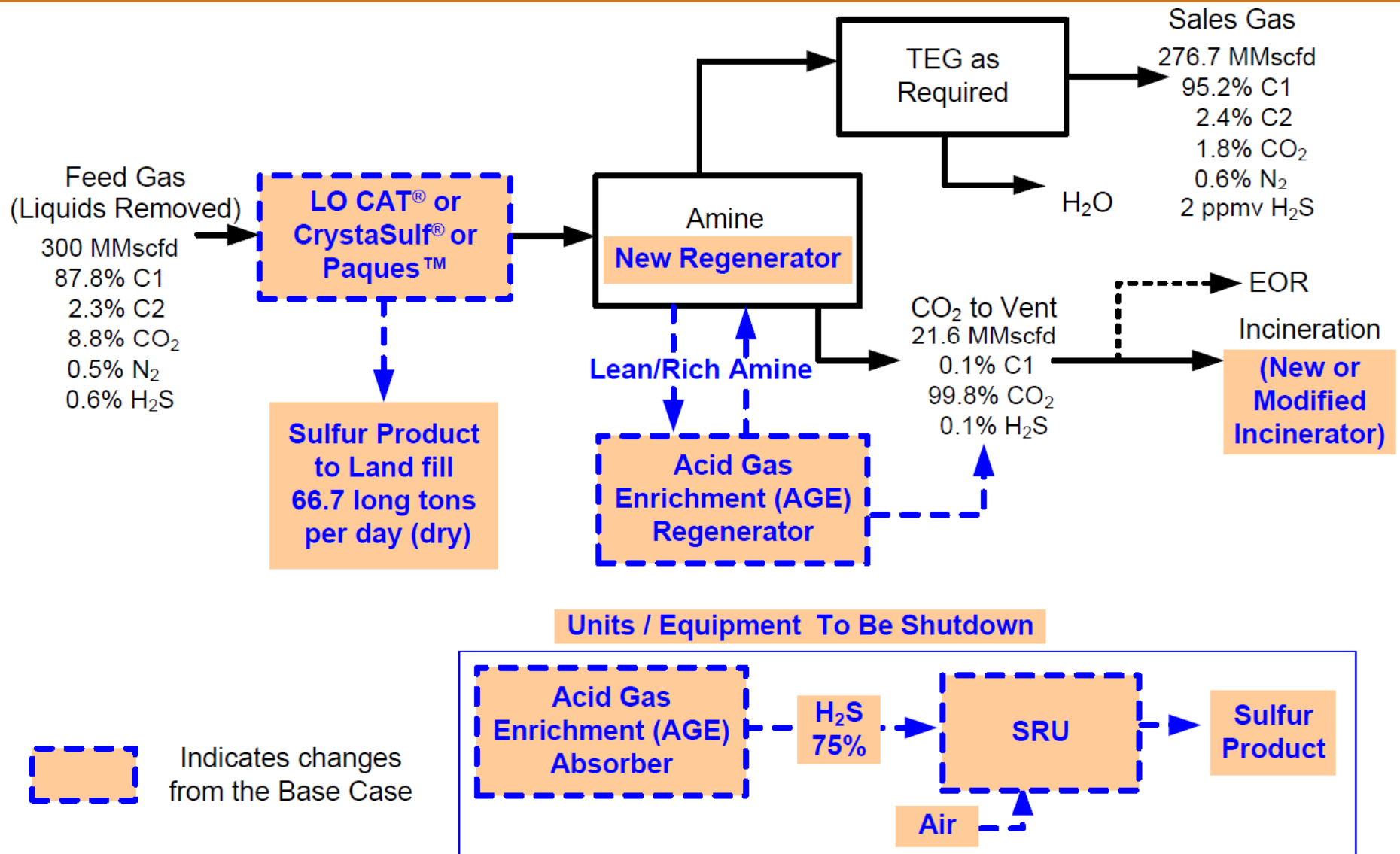
- Impact Shale Gas Has in Retrofit Case One versus the Base Case

- Amine Regenerator capacity increases 106% due to increase in CO₂
- AGE feed rate increases by 106%, likely requiring a new parallel unit.
- SRU feed is 20% H₂S and the flow rate has increased 58%
- The AGE enrichment could be increased to debottleneck the SRU
- To achieve 98% sulfur recovery only 2,980 lbs/day can remain in the SRU tail gas. In the Base case, the allowable amount was 7,080 lbs/day.
- Increase Incineration capacity by 40%
- Reduce liquid sulfur handling by 58%
- Need more steam generation to support two new amine regeneration reboilers, coupled with less steam generation from the SRU



Case Study – Case Two

40% Sour Natural Gas / 60% Shale Gas



Case Study – Case Two

40% Sour Natural Gas / 60% Shale Gas

- **Impact Shale Gas Has in Retrofit Case Two versus the Base Case**
 - Existing AGE Absorber, SRU and Sulfur Product Handling can be shutdown
 - Eliminates AGE solvent requirements
 - Amine Regenerator capacity will need to increase 91%
 - AGE Regeneration System could be re-purposed to provide some additional amine regeneration capacity
 - Sulfur Product would likely be land filled
 - 65.5 long tons per day plus moisture and residual solvent that can nearly double the weight of the total material to be land filled
 - CO₂ vent is increased, resulting in 13% additional Incinerator capacity



Conclusions

- **Shale Gas compositions vary widely from field to field and even within a given field**
- **Need to match process configuration changes with Shale Gas processing capacity**
- **The lower H₂S content will likely affect an existing plant's sulfur handling systems**
- **Higher CO₂ complicates the sulfur processing**
- **A large number of processing possibilities**
- **Process selection is very heavily site dependent**
- **New Sulfur Recovery Technology recovery options have potential but come with new issues**
- **Sulfur processing capacity may need to be over-built to cover swings in Conventional vs. Shale Gas at a particular location**



QUESTIONS?

