BERRY PETROLEUM COMPANY

HEAVY OIL CONFERENCE CALL – JANUARY 2012

Safe Harbor and Cautionary Note

Safe Harbor Under the Private Securities Litigation Reform Act of 1995

This presentation contains forward-looking statements concerning expectations about the Company's future business and results of operations. Words such as "anticipate," "can," "could," "will," "intend," "continue," "target(s)," "expect," "achieve," "strategy," "future," "estimated," or other comparable words or phrases or the negative of those words, and other words of similar meaning indicate forward-looking statements. These statements include but are not limited to forward-looking statements about acquisitions of properties, expectations of plans, strategies, objectives and anticipated financial and operating results of the Company. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including those discussed under "Risk Factors" in the Company's SEC filings, which could cause its actual results to differ from those projected in any forward-looking statements that it makes. The Company believes that it is important to communicate its future expectations. However, there may be events in the future that the Company is unable to accurately predict or control and that may cause its actual results to differ materially from the expectations describe in its forward-looking statements. Forward-looking statements speak only as of the date of such statement.

Cautionary Note Regarding Hydrocarbon Disclosures

The U.S. Securities and Exchange Commission (SEC) requires oil and gas companies, in filings made with the SEC, to disclose proved reserves, which are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, under existing economic condition, operating methods, and governmental regulations. Beginning with year-end reserves for 2009, the SEC permits the optional disclosure of probable and possible reserves. The SEC defines "probable" reserves as "those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC defines "possible" reserves as "those additional reserves that are less certain to be recovered than probable reserves." The Company applies these definitions in estimating probable and possible reserves. Statements of reserves are only estimates and may not correspond to the ultimate quantities of oil and gas recovered. Any estimates provided in this presentation that are not specifically designated as being estimates of reserves may include estimated quantities not necessarily calculated in accordance with, or contemplated by, the SEC's reserve reporting guidelines. The Company uses terms describing hydrocarbon quantities in this presentation including "oil in place," "resource," "risked resource," and "barrels in place" that the SEC's guidelines prohibit it from including in filings with the SEC. These estimates are by their nature more speculative than estimates of reserves prepared in accordance with SEC definitions and guidelines and accordingly are substantially less certain. Investors are urged to consider closely the reserves disclosures in the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Unless otherwise stated, hydrocarbon volume estimates have not been risked by Company management. Factors affecting ultimate recovery include the scope of the Company's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, commodity prices, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors, and actual drilling results, including geological and mechanical factors affecting recovery rates. Accordingly, actual quantities that may be ultimately recovered from the Company's interests will differ substantially from its estimates of potential reserves, and could be significantly less than its targeted recovery rate. In addition, the Company's estimates of reserves may change significantly as development of its resource plays and prospects provide additional data.

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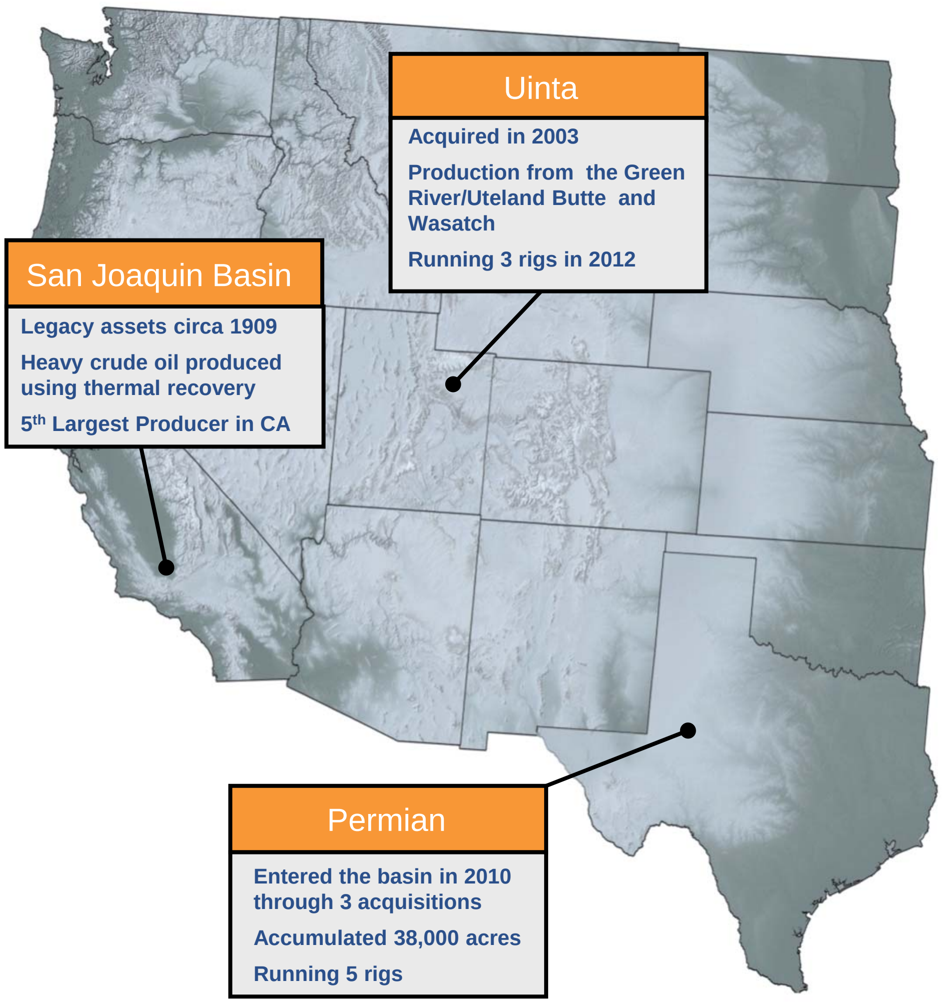
Company Profile

90% of 2011 Development Capital Invested in 3 Oil Basins

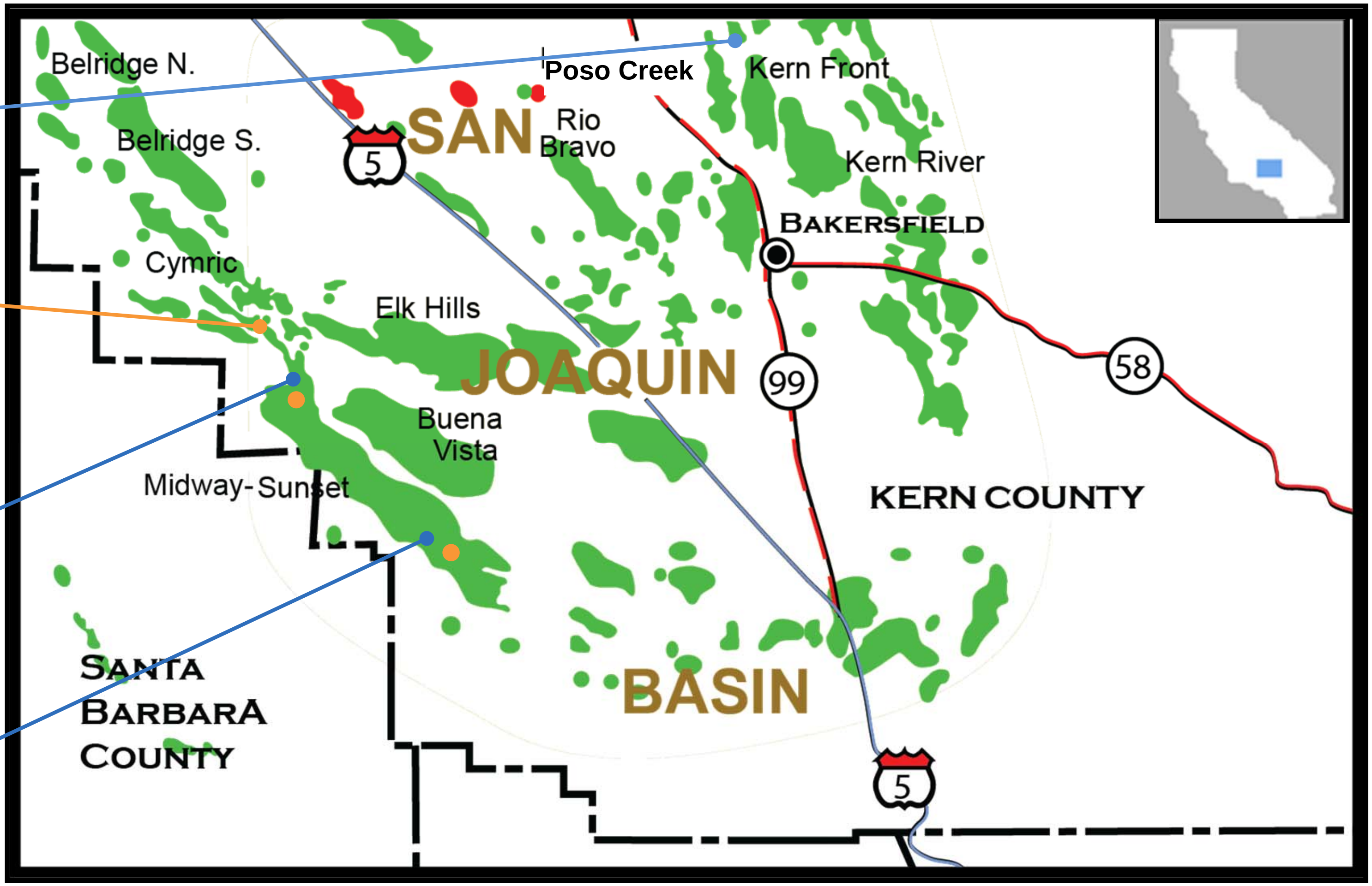


Key Statistics	
Proved Reserves	271 MMBOE
% Proved Developed	49%
2010 Production	32.7 MBOED
2011E Production	~36.0 MBOED
2011E Capital	$525 MM
2011E % Oil	70%
2012E Production Growth	~10%
2012E Capital	~$600 MM

Berry's California Assets

~500 MM Barrels of Oil in Place Under Development

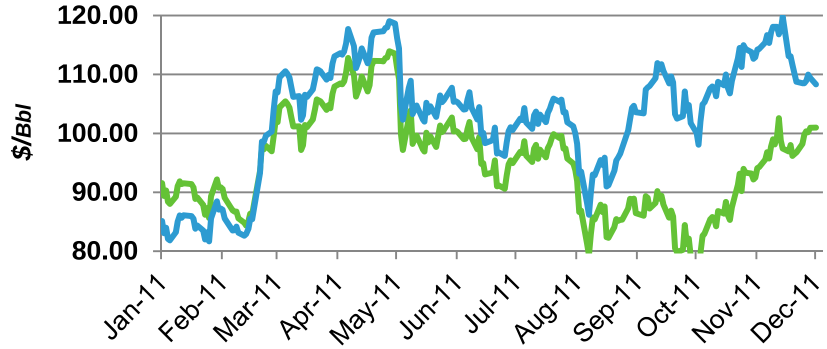
Poso Creek	***Model Steam Flood***
McKittrick 21Z	***One of 5 early stage Steam Floods***
N. Midway Diatomite	***Berry's largest development project***
S. Midway-Sunset	***Berry's legacy oil asset***



Pilot Steam Flood Area

California Crude Oil Fundamentals

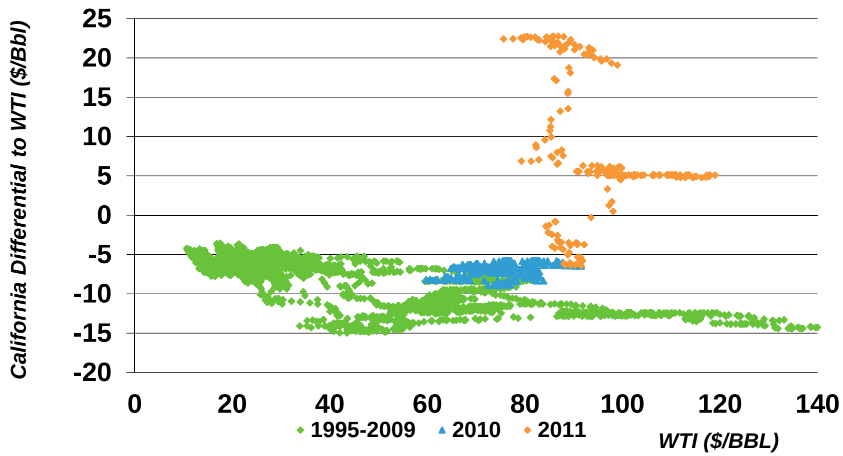
WTI vs. Midway-Sunset Crude Pricing



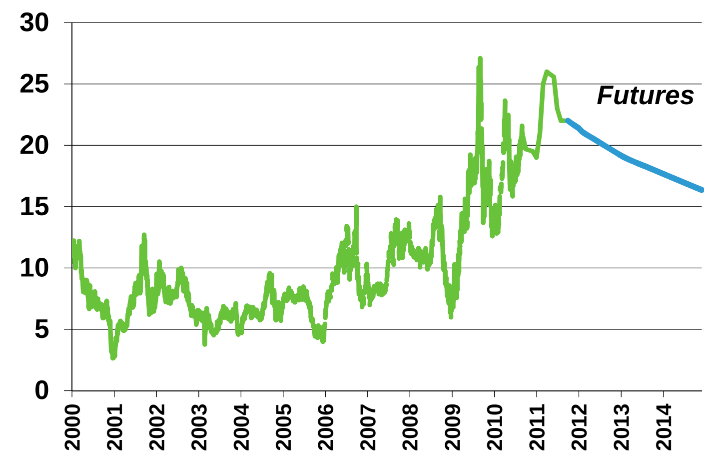
California Gross Operated Oil Production (MBbl/D)

	2008	2011
Chevron	*185*	*160*
Aera (Shell/Exxon)	*165*	*146*
Oxy	*65*	*69*
Plains	*36*	*34*
Berry	*16*	*20*
Seneca	*8*	*7*
Total	*475*	*436*

15-Year California Differential vs. WTI

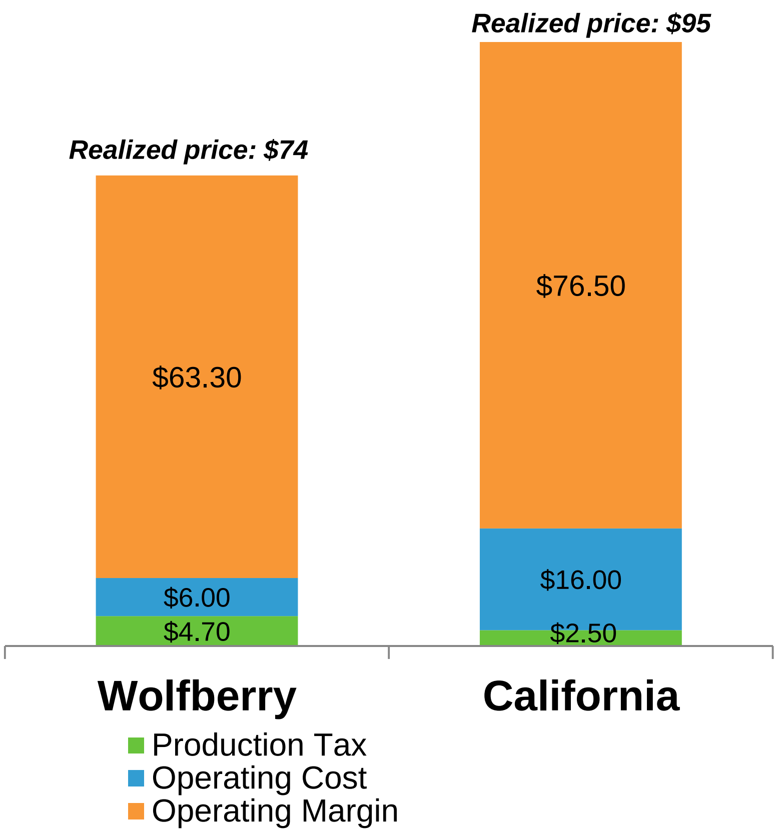


Oil to Gas Price Ratio



California and Permian Drive Corporate Margins

Illustrative Margin Comparison at $90 WTI and $4.50 HH

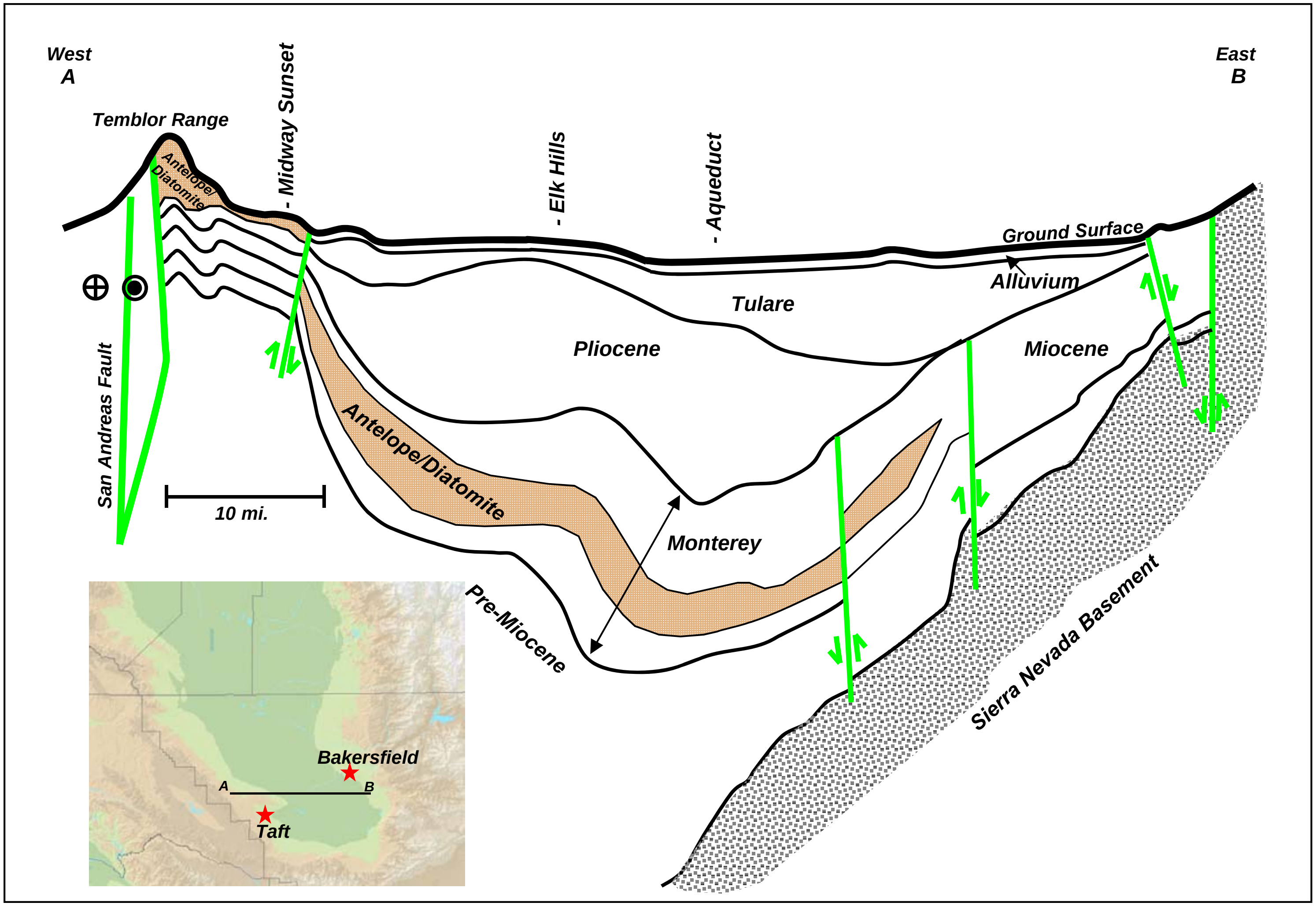


Commentary

- Wolfberry and California assets have strong margins with complimentary characteristics
- Current premium to WTI supports California asset margins
- Wolfberry assets are approximately 80% - 85% liquids
- Wolfberry assets generally have IPs in 120 BOED to 250 BOED range and a typical primary oil asset decline
- California assets are 100% low gravity crude and require steam injection to mobilize the oil
- California assets have low IP rates and a very shallow decline in the 6% - 9% range

Southern San Joaquin Valley

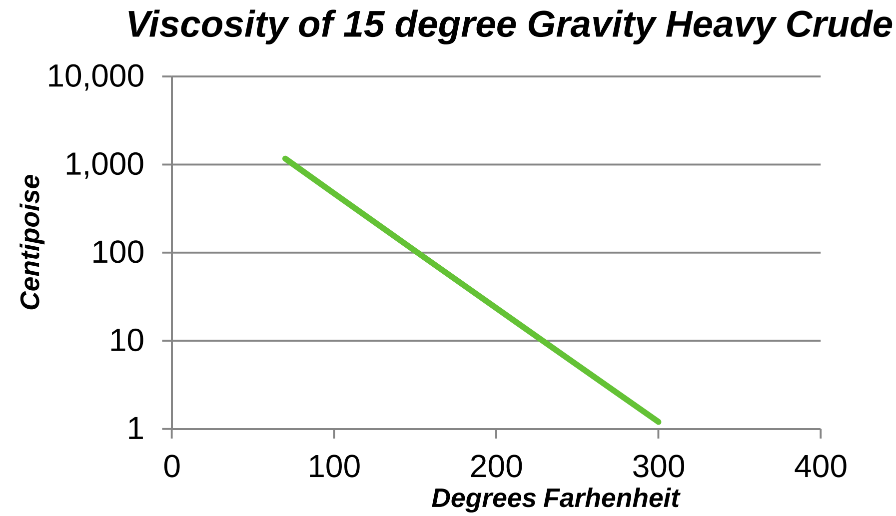
Geologic Cross-Section

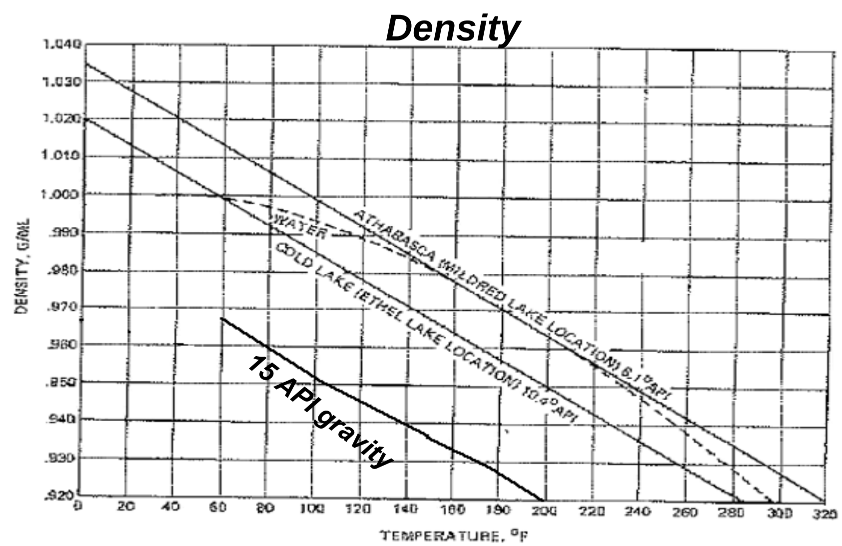


Heavy Oil Fundamentals

Viscosity Reduction, Key to Heavy Oil Thermal Recovery

- Berry's heavy oil in California generally has an API gravity of 13 – 15 degrees and has a much higher viscosity than light oil which has an API gravity of 42 degrees
- Viscosity is the resistance of a fluid to flow caused by internal forces (friction)
  - Higher viscosity is thicker
  - Pancake syrup is 2,500 cp at 68°F
- Heated fluid expands which:
  - Increases pressure
  - Increases volume
  - Reduces viscosity
  - Creates flow
- Berry uses steam to heat heavy oil

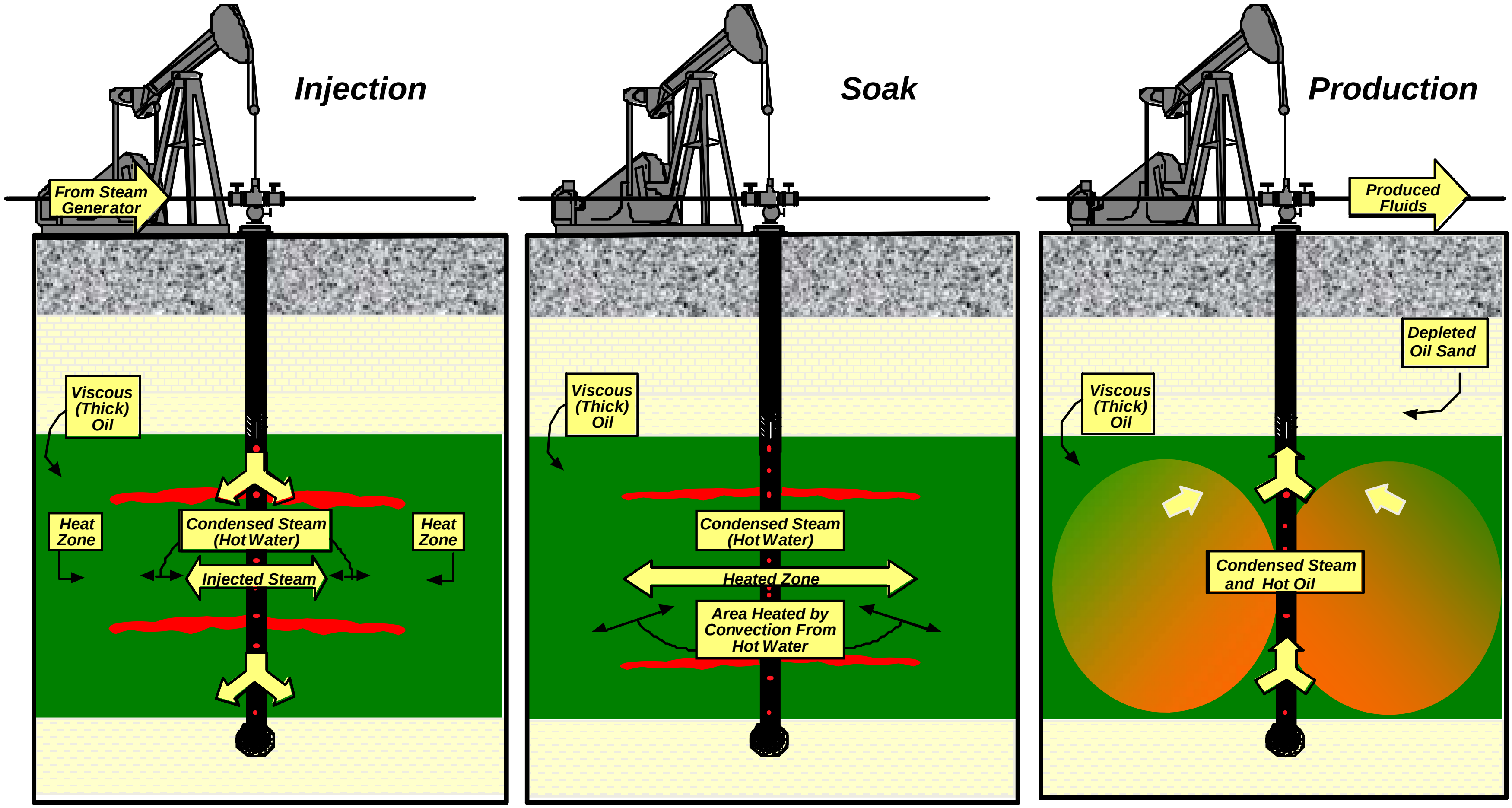




Density versus temperature for Cold Lake and Athabasca oil.[4]

Heavy Enhanced Oil Recovery

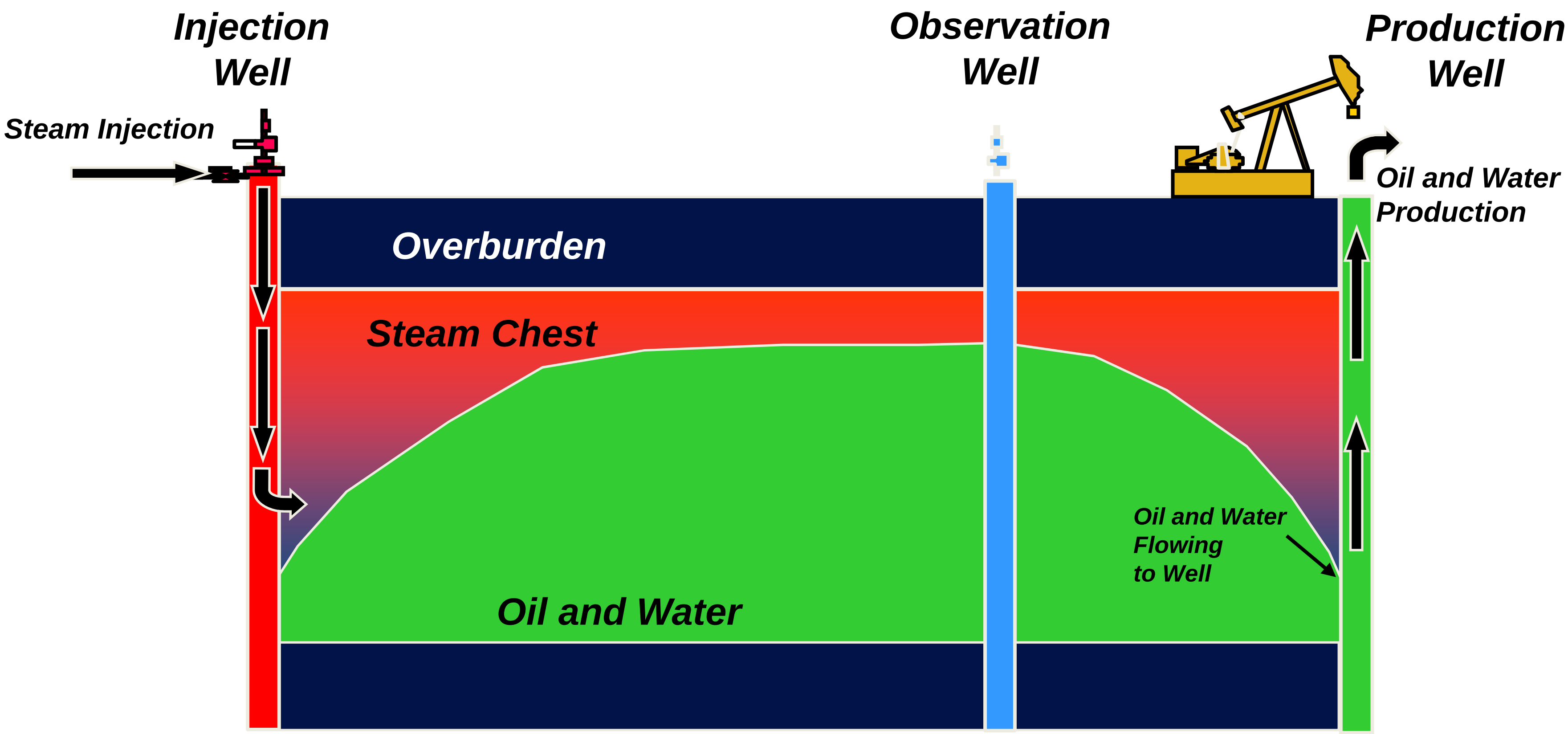
Cyclic Steam Injection is Simple Technique



~7000 barrels 70% steam | **3-7 days** | **6 months**

Enhanced Oil Recovery

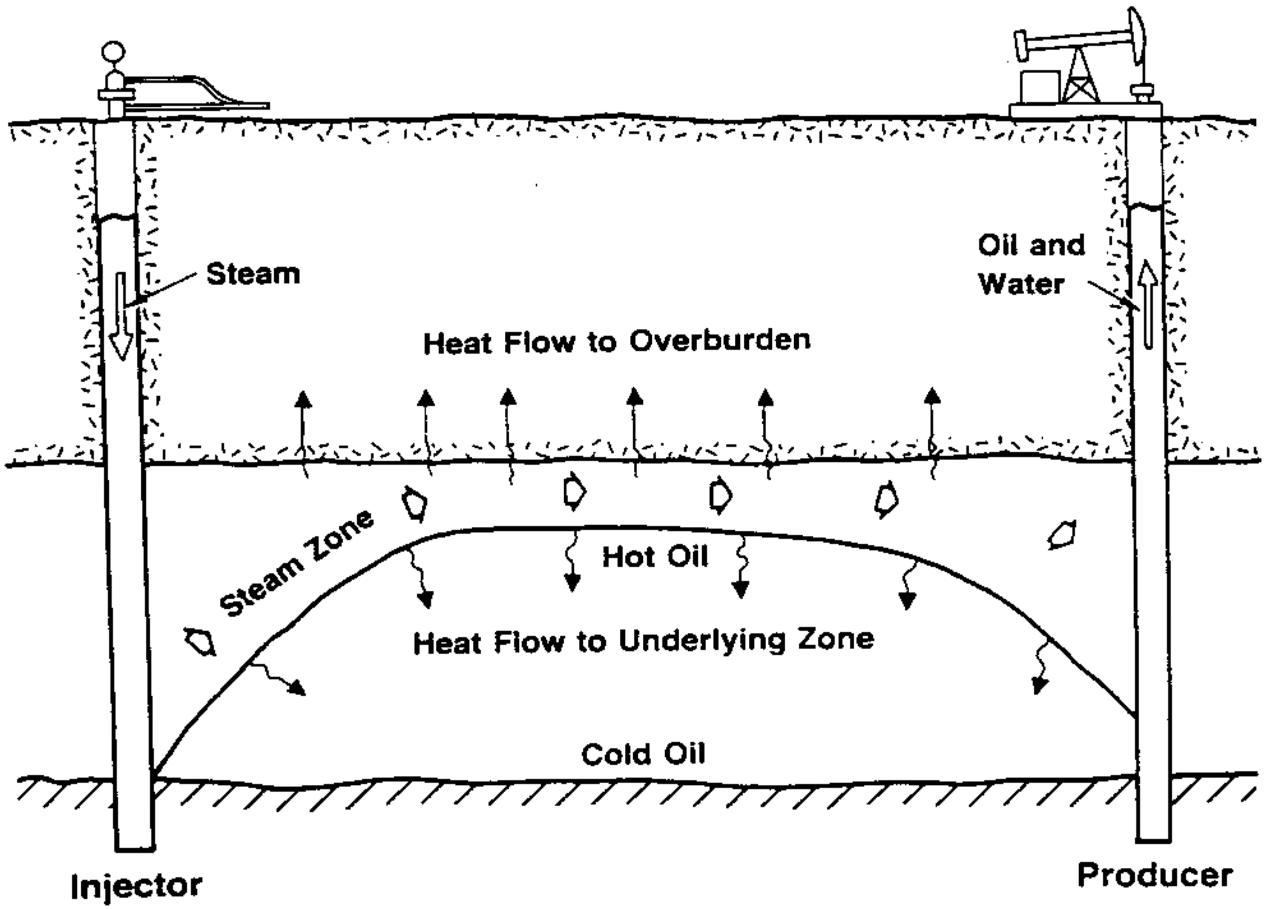
Continuous Injection Steam Flooding; Higher Recovery, Higher Cost



Heat Requirements for EOR

Calculating Heat Injection versus Heat Losses

Energy Balance Quantifies the Amount of Steam Required



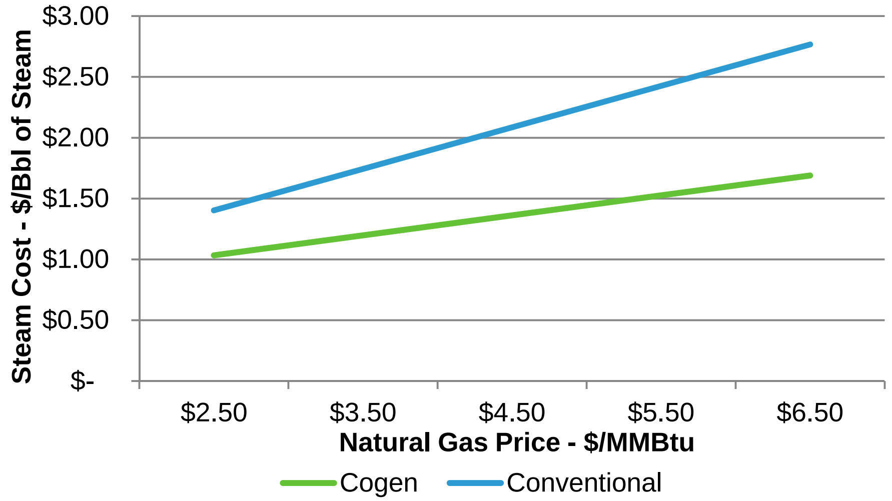
Heavy Oil Operating Costs

Driven by the Price of Natural Gas

Berry's Cogeneration Plants

- Berry operates three cogeneration facilities, two at S. Midway and one at Placerita which provide approximately 37,500 BSPD
- Berry's incremental steam capacity is provided from conventional steam generators
- Operating costs in California are driven by the natural gas price which directly impacts the cost of steam
- The amount of steam required to produce a barrel of heavy oil is referred to as the steam:oil ratio
- Berry's project's have steam:oil ratios between 5:1 and 10:1
- At a $5 natural gas price, a project with a 6:1 steam:oil ratio has per barrel steam operating costs of approximately $10 per barrel
- Additional non-steam operating costs are in the $6 - $12 per barrel range

Cost Comparison – Cogen vs. Conventional



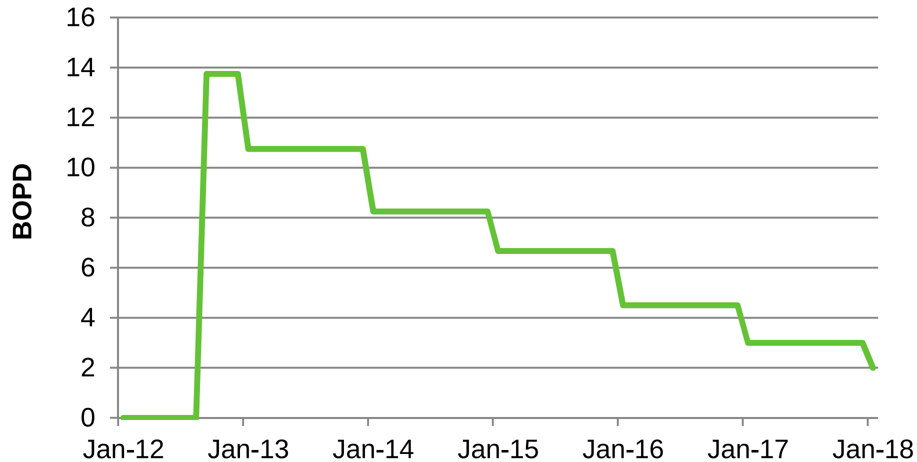
Conventional Steam Generator

Development Costs and Type Curves

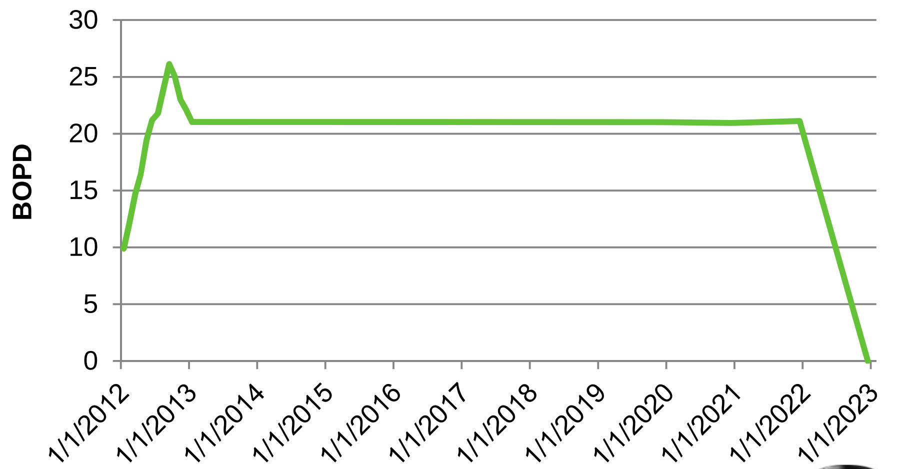
Commentary

- California heavy oil wells are generally less than 2000' deep
- Wells are not hydraulically fractured
- Drilling time is 2 - 4 days
- Wells generally cost between $150,000 and $400,000
- Additional development costs are needed for processing facilities and steam generation equipment
- Recovery of the original oil in place depends on the reservoir quality and viscosity of the oil and ranges from 20% to over 70%
- In general, F&D costs in California are in the $8 - $10 per barrel range
- Once heated, well declines are shallow and have long production lives

Illustrative Cyclic Steam Type Curve



Illustrative Diatomite Type Curve



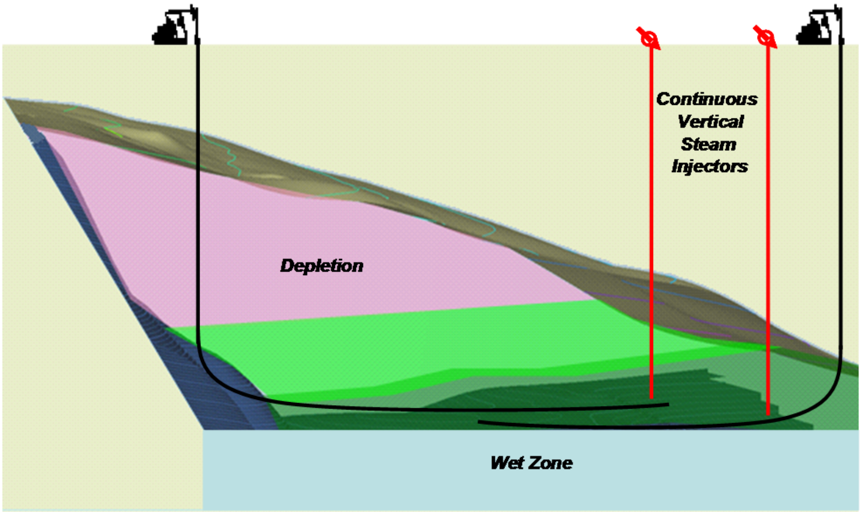
S. Midway-Sunset

Free Cash Flow Funds Berry's Development

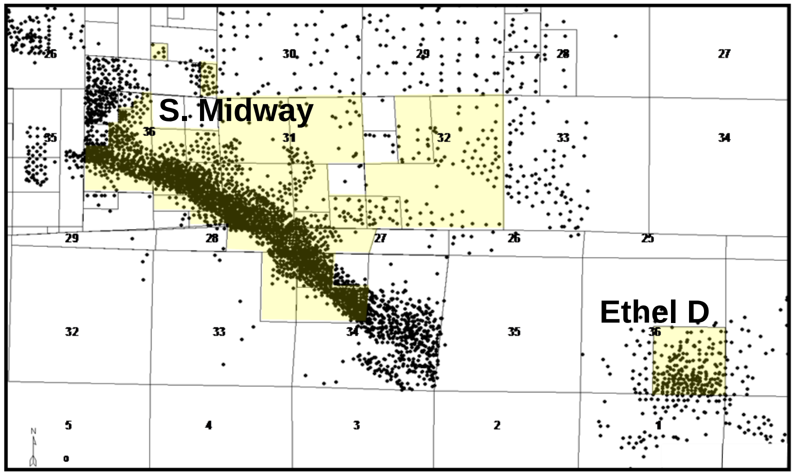
Asset Highlights

- Stable production from the 4th largest field in the U.S
- 8,000 BOPD from 2,000 acres, 95% working interest, 94% NRI
- Heavy crude (13° API) produced using steam injection with development focused on deeper pay zones and continuous injection in flanks
- S. Midway asset team should deliver over $200 MM of cash flow in 2012

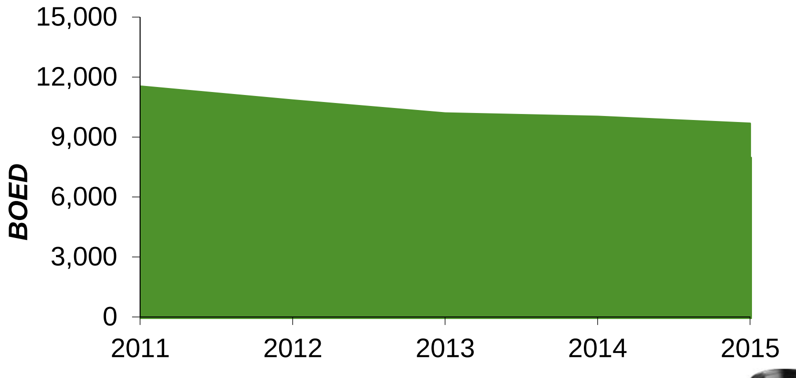
Continuous Steam Injection at S. Midway



S. Midway-Sunset Field Map



South Midway Asset Team



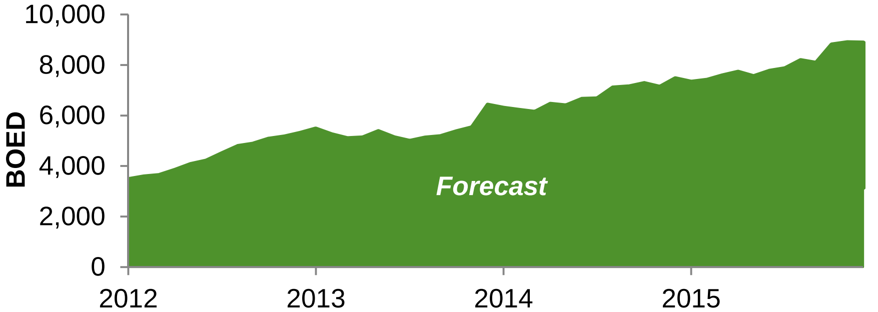
S. Midway, Poso Creek, Placerita

Next Generation Heavy Oil Projects

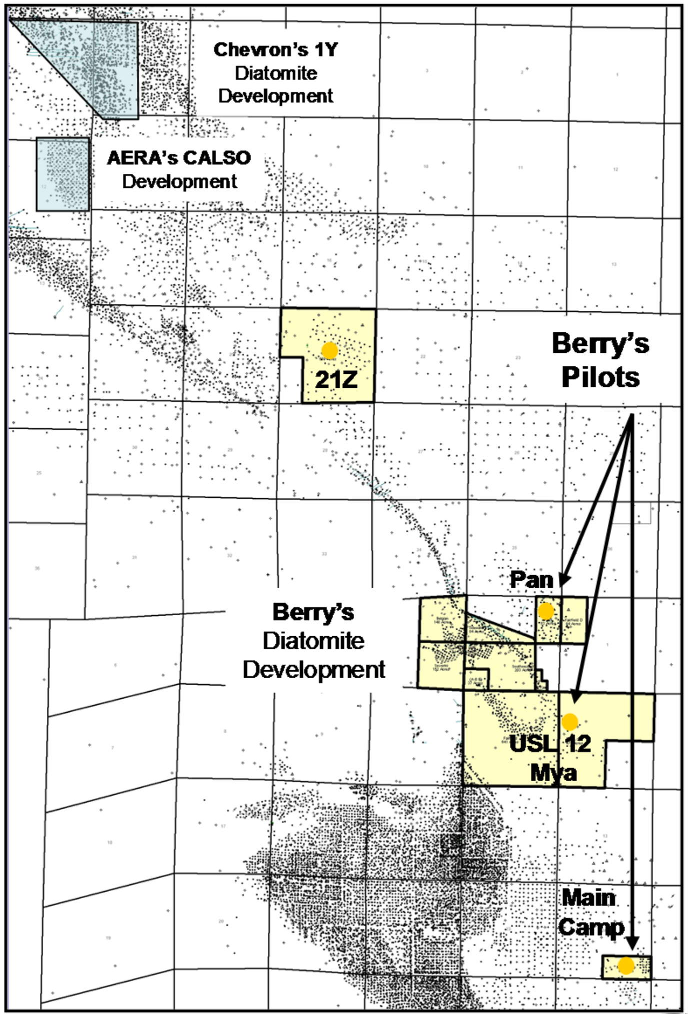
Commentary

- Next generation heavy oil projects are higher viscosity with higher steam to oil ratio and tighter spacing than traditional Midway-Sunset developments
- 50-well development in 2011 at 21Z, additional 50 wells in 2012
- Berry's other steam flood pilots (Pan, Mya, Main Camp) are in progress
- Permitting is not expected to impact development

Next Generation Steam Flood Production Forecast (BOED)



Project Locator Map



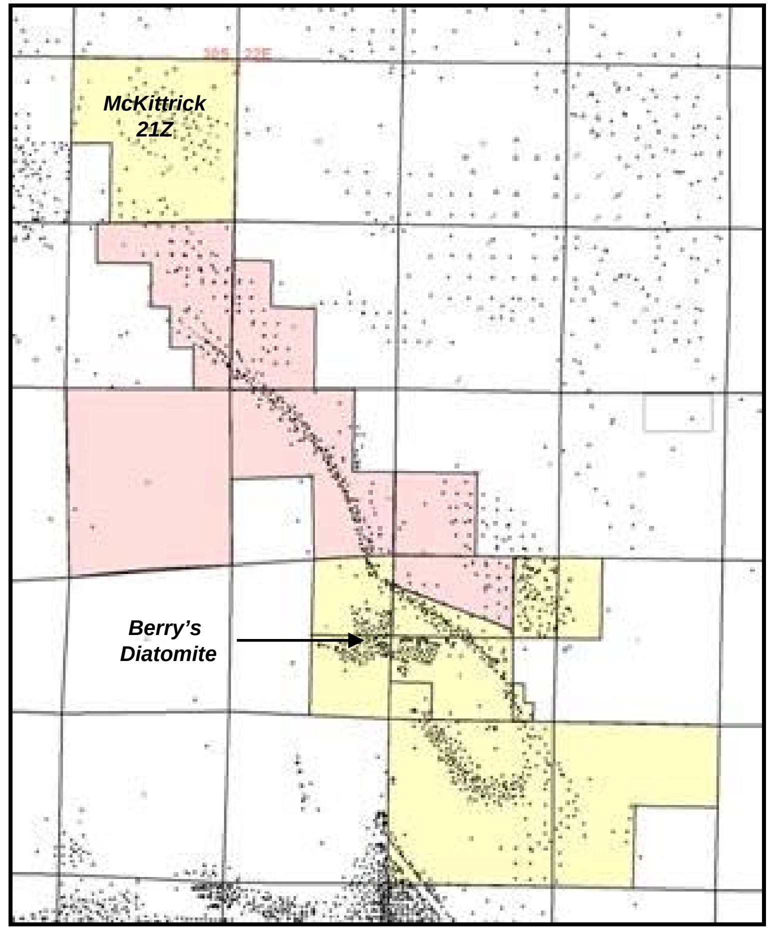
Diatomite Resource

360 Million Barrels in Place on 540 acres

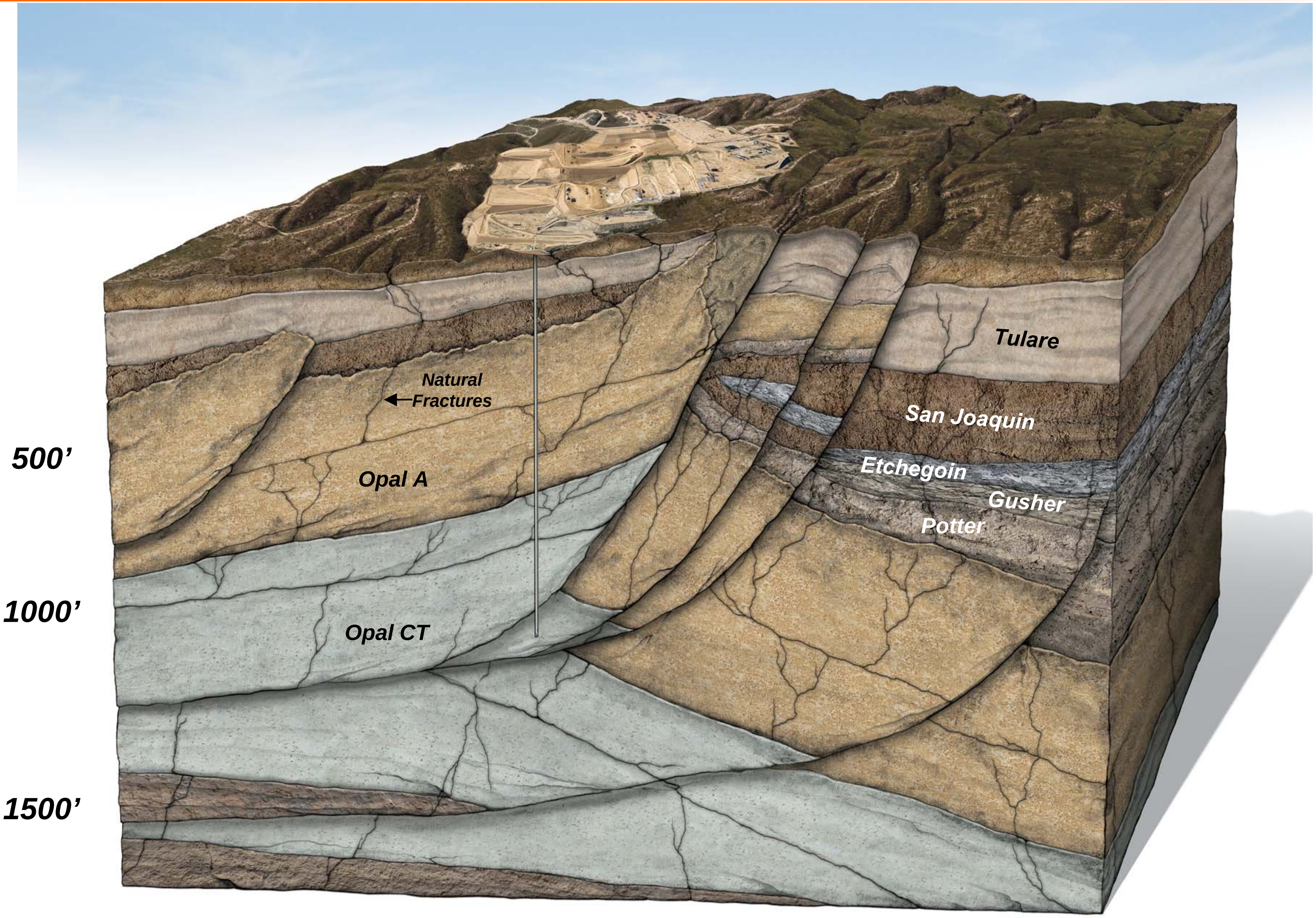
Asset Highlights

- 540 acres, 100% working interest, 90% NRI
- 350 wells drilled with full development of 1,000 total wells on half-acre spacing
- Diatomite contains 15° API gravity heavy oil
- Average depth of 800 feet
- 360 million barrels of oil in place, targeting 23% - 40% recovery or 83 – 144 MMBOE
- Upside comes from increased recovery and lower steam oil ratio (SOR)
- Seeking additional acreage acquisitions near the Company's existing assets
- Plan to drill 60 wells in 2012

Diatomite Field Map



Diatomite Resource
Shallow Wells Target Thick Pay

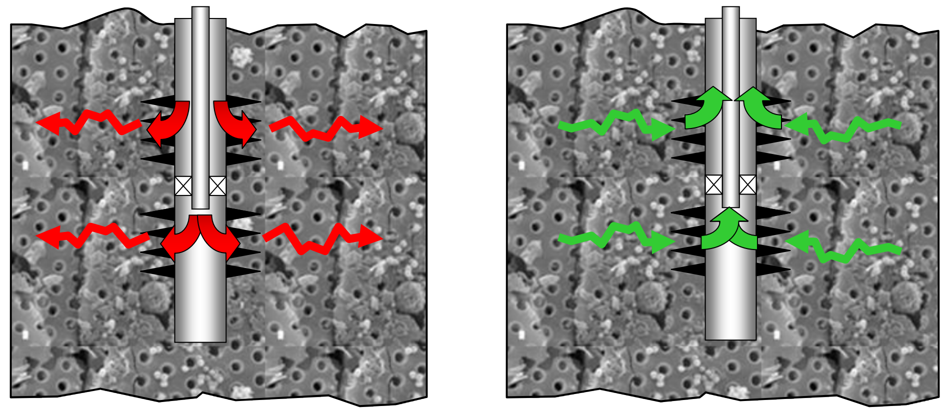


Recovery Process Design & Steam Stimulation Control

- Berry injects small, calculated volumes of steam into producing wells followed by a controlled flow back period.
- These cycle volumes are customized according to the depth of injection and actual volumes injected at reservoir conditions for each well.
- Each injection/production cycle alters existing reservoir stress conditions, inducing new fracture growth with each new cycle.
- Wellbores are completed from the bottom up, confining steam initially to the lower portions of the reservoir.
- Over time, as each interval is depleted, the wellbore is recompleted in the next productive zone above the previously targeted zone.
- The sequential completion process is repeated until the entire pay interval has been depleted, or until there is a minimum of 250 feet of overburden remaining.

Cyclic Steam Process

Steam Injection Cycle	Production Cycle

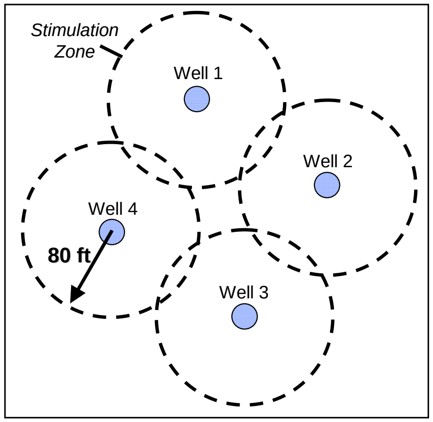


Small, controlled steam injection cycles are applied to limit lateral fracture growth and prevent steam breakthrough with offset wells	***Induced reservoir pressure from the injection cycle drives oil from the reservoir to the wellbore and is produced at the surface***

Recovery Process Design & Steam Stimulation Control
Steam Stimulation Is Controlled

- Cyclic steam injection has been determined as the best method for hydrocarbon recovery of diatomite reservoirs
- This method also has two other operational advantages:
  - Limits fracture growth and
  - Limits build-up of reservoir pressure.
- Wells are completed with a minimum of 250 feet of overburden.
- Sequential completions are used to confine steam to lower intervals of the reservoir.
- Operations and Engineering personnel utilize an extensive steam management program to:
  - Continuously regulate injection pressures and injection rates using automated controls
  - Control fracture growth by limiting:
    - Injection pressure
    - Steam injection rate
    - Injection volumes per cycle, depending on depth

Stimulation Radius



Typical Wellhead Configuration

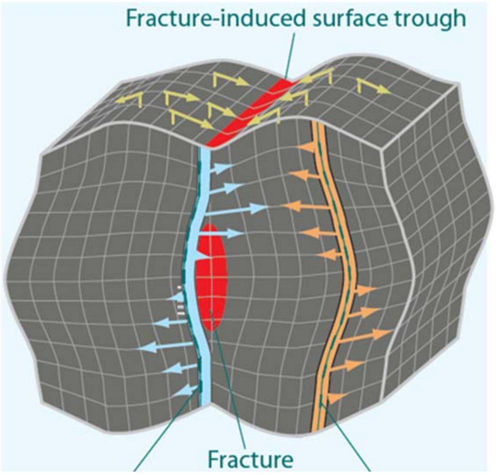
Reservoir Management

Using Surveillance Technology to Balance Injection and Withdrawal

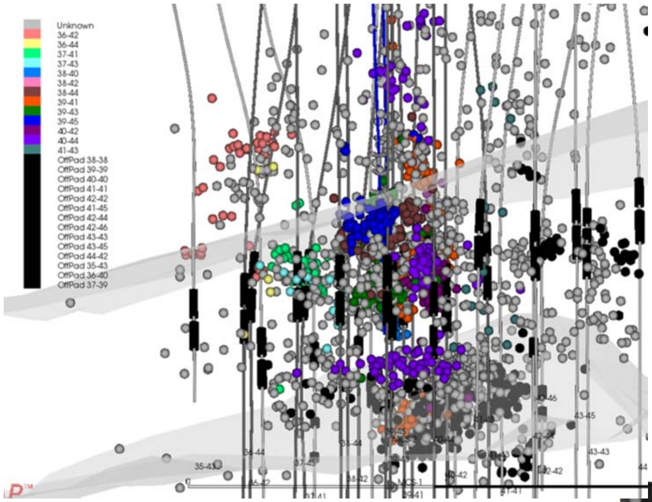
Commentary

- Berry is applying existing and new technology to monitor steam in the reservoir
- Tiltmeter and microseismic surveys directly measure deformation and resulting seismic events during cyclic steaming.
- Tiltmeters calculate the direction of primary stress in the reservoir and the uplift at the surface
- Microseismic identifies fracture events both in the reservoir and above as we cyclic steam
- Berry is building a surveillance system that will monitor the tiltmeter, microseismic and other data to balance injection and withdrawals from the reservoir

Surveillence Monitoring



Microseismic Monitoring



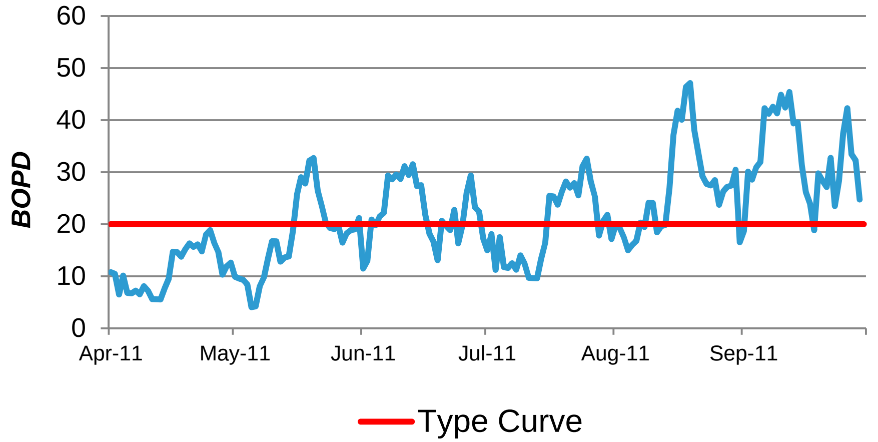
Diatomite Reservoir is Performing

Maximizing Online Completions

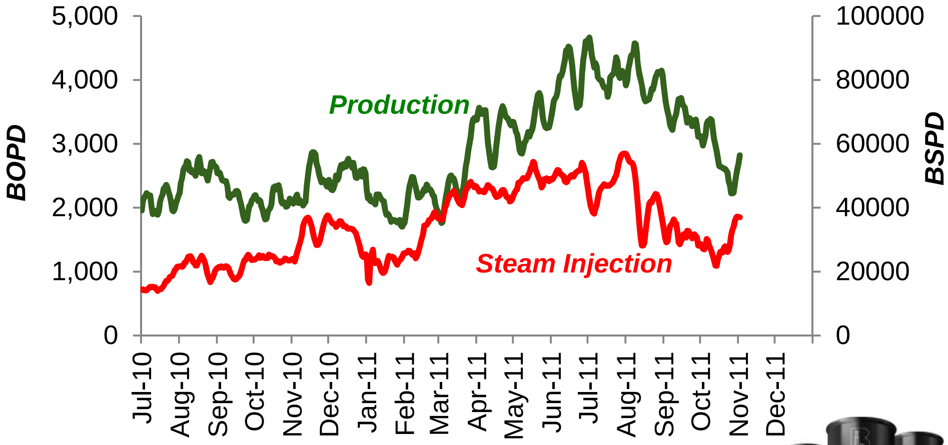
Commentary

- Completions in the diatomite are performing on the type curve at approximately 20 BOPD
- Project approval received in Q3 2011 from DOGGR requires that production be shut-in near damaged wellbores
- Formal regulatory approvals are required to reinject steam near damaged wellbores once mitigation steps are taken
- Regulatory approvals can take as long as 90 days to process
- Production has declined to 2,500 BOPD with approximately 100 of 250 wells offline
- A more responsive approval process could improve the number of completions online and could improve Berry's production growth
- Optimizing steam injection to minimize wellbore damage which should reduce the need for regulatory approvals and increase the number of completions that are online

Illustrative Diatomite Completion Performance



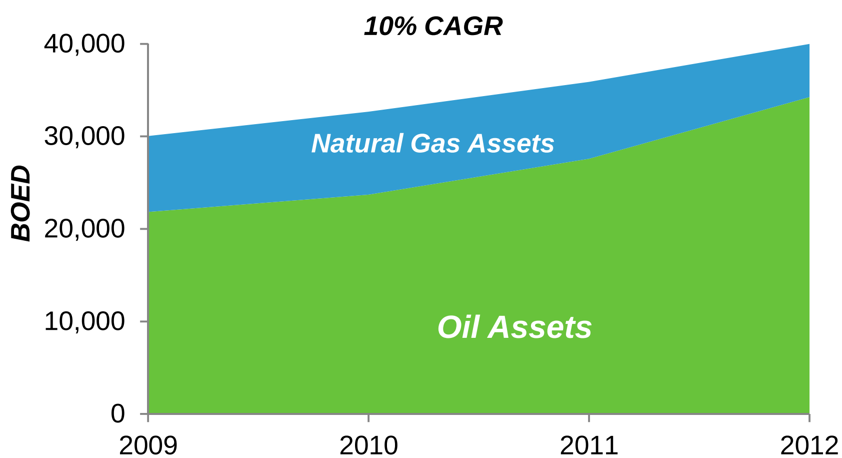
Diatomite Net Daily Production



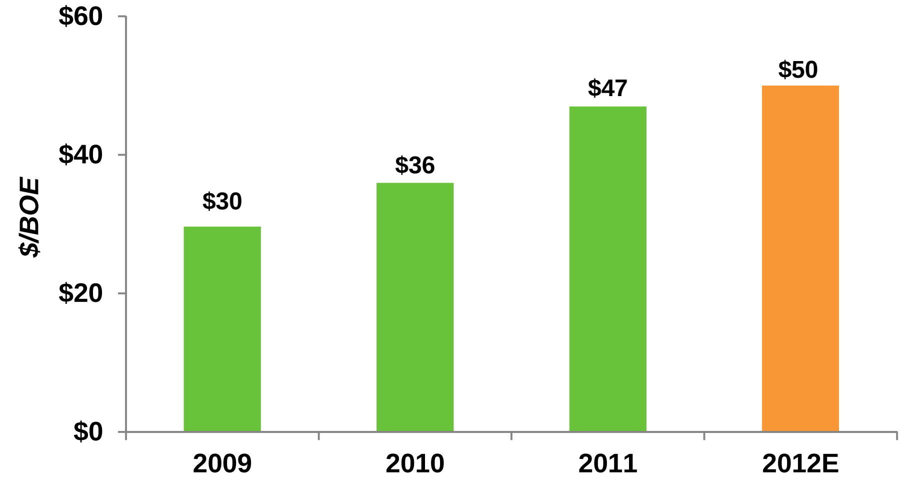
Track Record of Growth

Investing in Oil Assets to Grow Production, Margin and Cash Flow Per Share

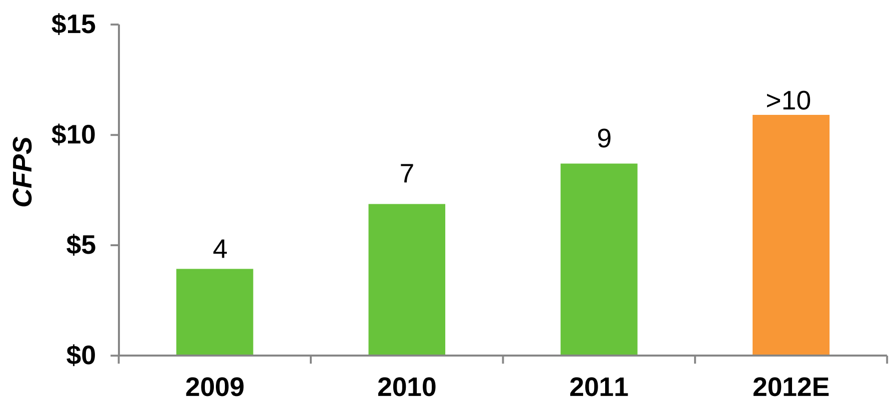
Grow Production Double Digit



Improve the Margin to over $50/BOE at $90 WTI



Grow Cash Flow Per Share



Commentary

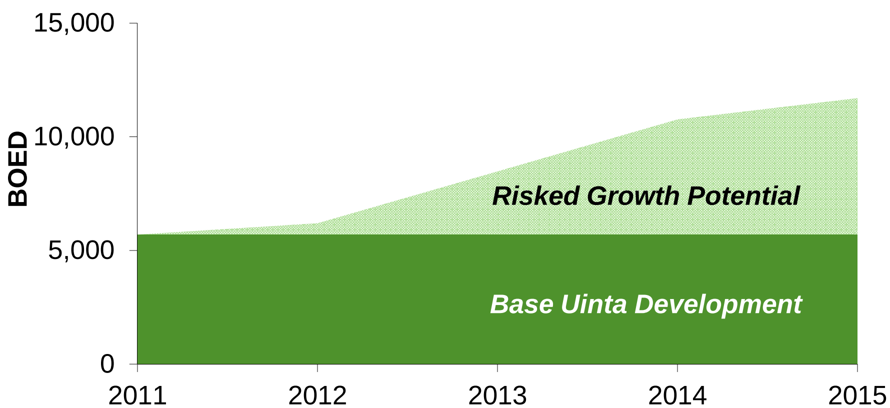
- Berry has a track record of growing production, margin and cash flow
- Investing 100% of capital in 2012 into three oil basins will allow for continued oil production, margin and cash flow growth
- Oil will increase to 75% of production and margin to over $50/BOE in 2012 at current prices

Uinta Assets
Overview

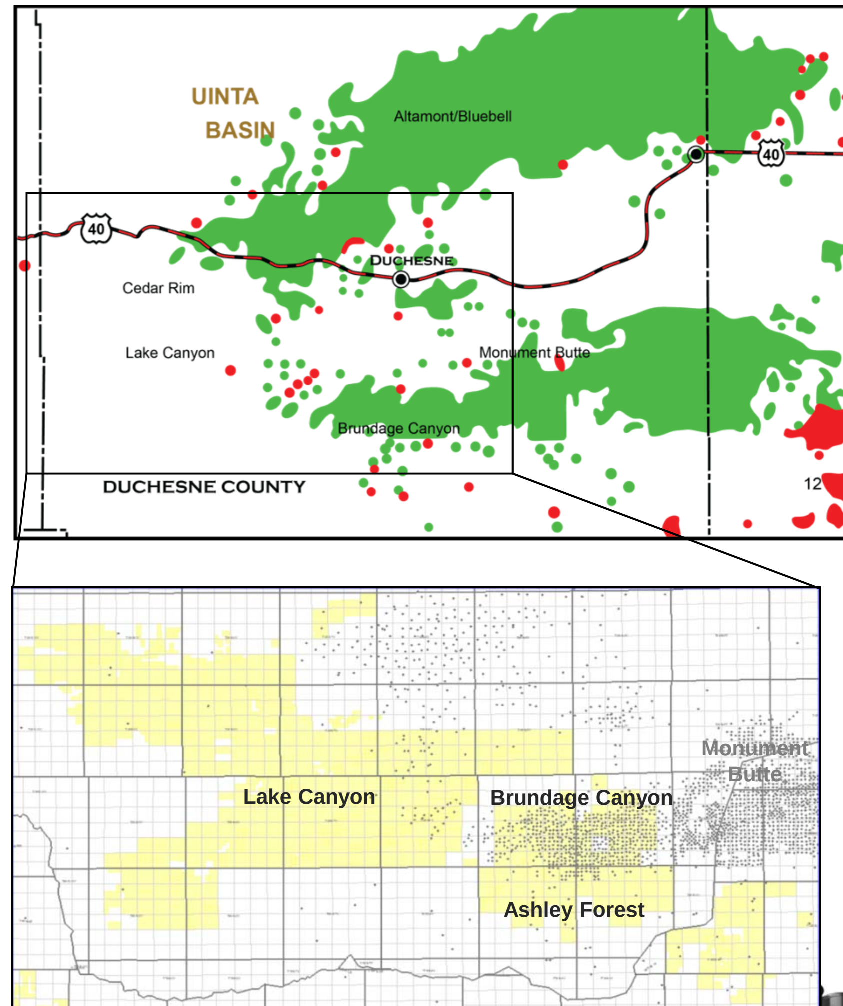
Asset Highlights

- Acquired in 2003 and 2004 with 55,000 acres in Brundage Canyon with 100% WI and 174,000 acres in Lake Canyon with 42.6% average WI
- 500 Producing wells on 40-acre spacing
- Historically 60% crude oil and 40% gas, Uteland Butte/Wastach have been more oily
- New development in the Uteland Butte and Wasatch could allow Berry to double its Uinta basin production

Uinta Production Forecast



Uinta Basin Map



Uinta Resource

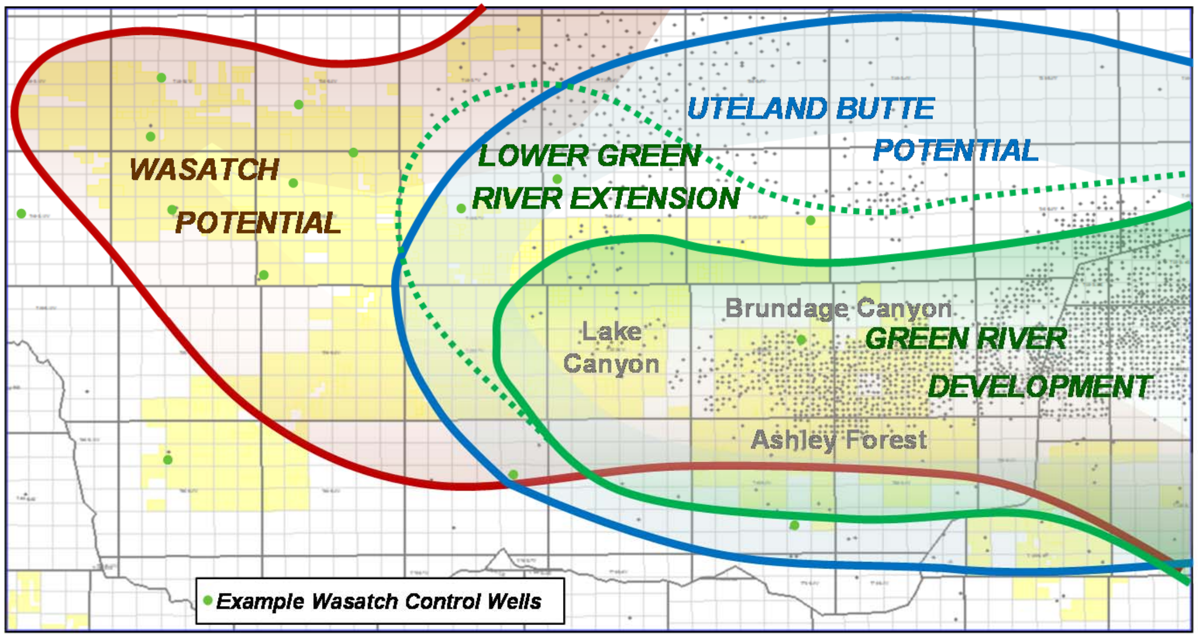
Multiple Targets Across Large Acreage Position

- 75 MMBOE of risked resource in the Green River, Uteland Butte and Wasatch which includes 11 MMBOE of proved developed reserves
- Significant number of vertical penetrations into each formation which were used to determine the extent of the reservoirs
- Drilling will provide the ability to de-risk the resource

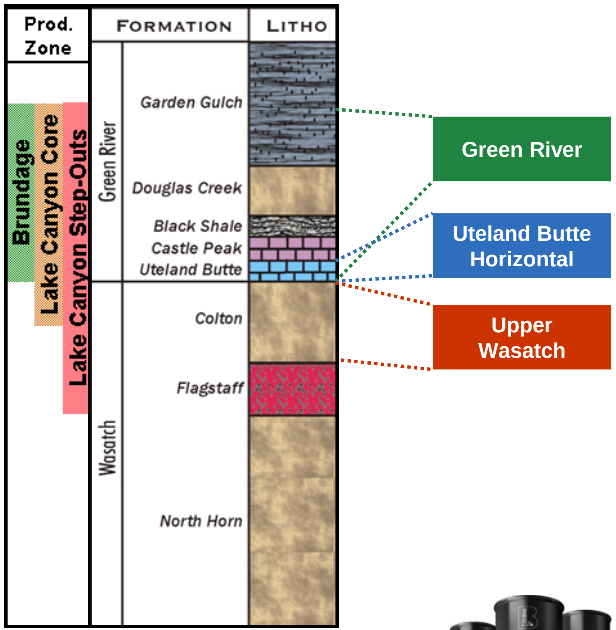
Acreage Summary

Area	Prospective Acres		Average Ownership	
	Gross	Net	WI%	NRI%
Green River	78,000	57,400	73.6%	62.0%
Uteland Butte	109,450	63,350	57.9%	48.5%
Wasatch	191,650	101,850	52.7%	43.6%
Total			**61.8%**	**51.8%**

Uinta Resource Fairways



Target Formations

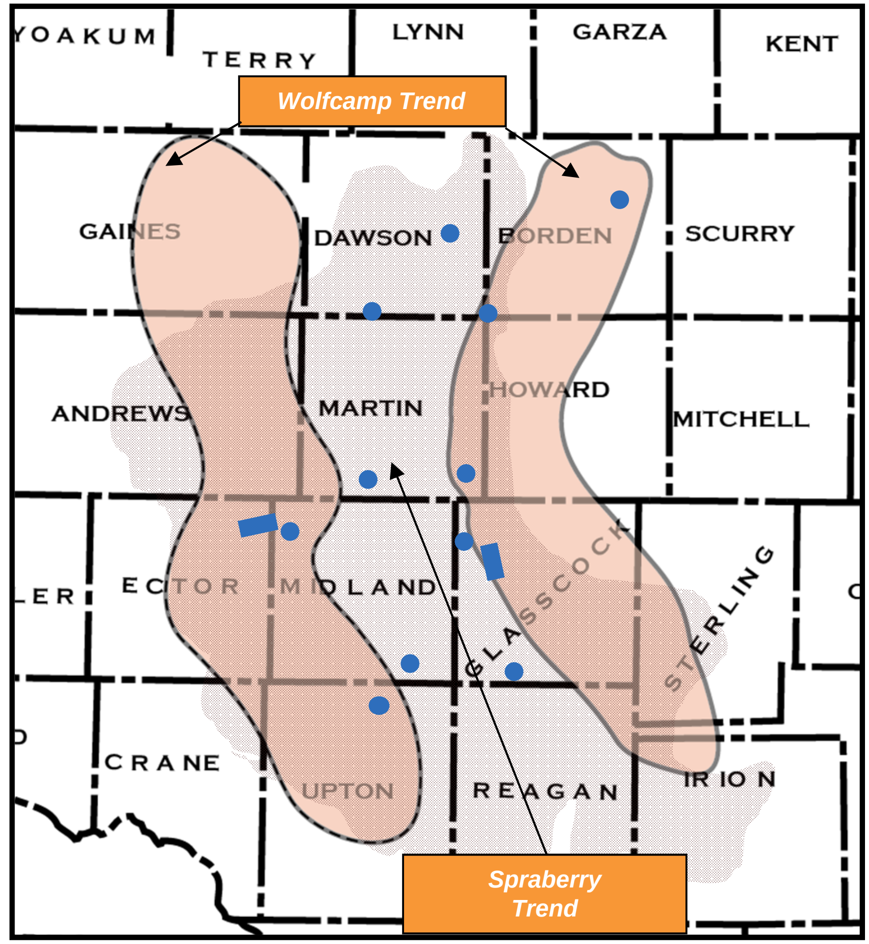


Berry's Wolfberry Assets

Commentary

- Total of 38,000 net acres in the Permian, 75% NRI
- Plan to run five rigs in 2012
- Expect production to grow to 9,000 BOED over the next four years from current Permian assets
- Drilling inventory of over 450 locations on 40's and 650 locations on 20's in the Wolfberry
- Upside potential resides in 20-acre down spacing and in derisking the deeper formations
- Wolfberry IPs generally range from 120 BOED to over 250 BOED with expected EURs of 160 MBOE to 180 MBOE
- Production has been impacted by periodic gas curtailments as regional gas plants fill up and expand

Permian Asset Locator Map



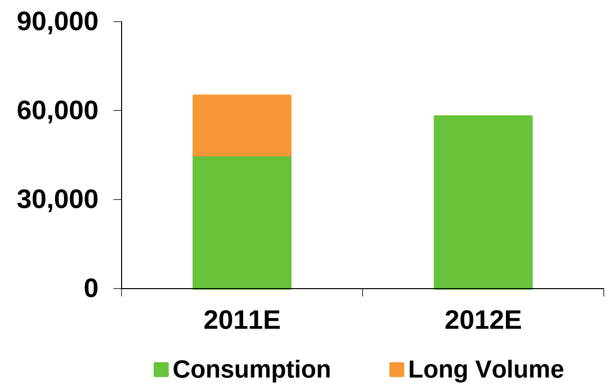
Natural Gas Assets

Consumption Reduces Sensitivity to Natural Gas Prices

Commentary

- Berry consumes over 50,000 MMBtu/D to produce steam in California which offsets Berry's gas production
- Have 15,000 MMBtu/d of natural gas production hedged in 2012 with a floor of approximately $6.00
- Changes in natural gas prices do not have a significant impact on Berry's cash flow

Natural Gas Balance



East Texas Asset Highlights

- Oakes property in Limestone County - 2,641 gross acres, 100 producing wells
- Darco property in Harrison County - 2,112 gross acres, 40 producing wells
- 95% working interest (80% NRI)

Piceance Basin Asset Highlights

- Garden Gulch property - 3,950 net acres (62.5% WI, 50% NRI)
- North Parachute property - 4,130 net acres (95% WI, 79% NRI)
- Approximately 150 producing wells

Maintaining the Current Strategy

Oil Investment in 3 Basins for Long-Term Growth

Concentrate Capital Investment in 3 Oil Basins	Grow Production to over 55,000 BOED, >80% Oil	Increase the Corporate Margin and Cash Flow Per Share
~ $600 million in 2012	*~ 10% Growth and 75% oil in 2012*	*> $10/share and $50/BOE at $90 WTI*