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CRC - California Resources Corp Analyst Day (Day 3)

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CORPORATE PARTICIPANTS

Scott Espenshade *California Resources Corporation - VP - IR*

Todd Stevens *California Resources Corporation - President, CEO*

Mark Smith *California Resources Corporation - CFO*

Carlos Contreras *California Resources Corporation - VP - Commercial*

Charlie Weiss *California Resources Corporation - EVP - Public Affairs*

Jerry Foster *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

Frank Komin *California Resources Corporation - EVP - Southern Operations*

Darren williams *California Resources Corporation - EVP - Exploration*

Francisco Leon *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

CONFERENCE CALL PARTICIPANTS

Doug Leggate *Bank of America - Analyst*

Welles Fitzpatrick *Johnson Rice - Analyst*

PRESENTATION

Scott Espenshade - *California Resources Corporation - VP - IR*

I'm Scott Espenshade, Vice President of Investor Relations of California Resources Corporation. I'd like to welcome all of you for attending in person as well as those listening in our webcast for CRC's 2015 Analyst and Investor Day plus our site tours that we're offering this time for those fortunate enough to attend.

As a reminder, today's presentation may include projections and other forward-looking statements within the meanings of the Federal Securities laws. These statements are subject to risk and uncertainties that may cause actual results different from those expressed or implied in these statements in today's presentations.

Additional information on factors that could cause results to differ is available in the company's 10-K filings and we would ask that you review it and the cautionary statements in the presentation here today. You'll also be able to access today's slides under the investor relations link on our CRC website at www.crc.com.

We're thrilled to be here today in Long Beach to discuss California Resources' assets in detail. Let me begin by giving you a sense what our team and I hope you will take away from these two days.

California is possibly the least understood world class oil and gas rich environment in the entire United States. It's a region with extraordinary potential for growth. It's the land as Todd likes to say that time forgot.

We're going to give you a deep, deep dive into the quality and scope of our assets; the high-proven technologies that we know out to deploy to be able to grow the value of the asset; the flexibility of our entire infrastructure to do so and the many levers we can pull to operate through this current though cycle; and through whatever emerges as new normal.

We look deeply in our assets and operations in both Southern and Northern California. Today, you're going to look at what - how we look at our waterflooding and steamflooding operations and give you a better understanding of how big fields really do get bigger.

We'll also update you on the steps and the flexibility to measure the current environment as well as meaningful progress towards deleveraging and the steps we're taking.

As for today's specific agenda, we'll begin day one with presentations from the following speakers: Todd Stevens, President and Chief Executive Officer; Carlos Contreras, Vice President of Commercial; Charlie Weiss, Executive Vice President of Public Affairs; Jerry Foster will give a primer, he's our Manager of IOR and EOR; and then Frank Kromin, Executive Vice President of our Southern Operations.

This will be followed by the site tour of our THUMS Islands for the attending participants. We'll also then head of the Bakersfield later today.

On day two, we will begin with webcasting our morning presentations which again will begin at 10:30 a.m. Eastern Time and should again last approximately two hours. At that time, we'll give you an overview of our exploration portfolio with Darren Williams, our Executive Vice President of Exploration.

Then Bob Barnes, our Executive Vice President of our Northern Operations will provide an overview of northern assets as well as Elk Hills and we'll conclude the morning with the steamflood primer by Dr. Vic Ziegler, Director of our Corporate Development, and Jeff Hatlen, our Chief Reservoir Engineer of our Thermal Operations.

Today's presentation should last approximately two hours. We kindly ask that you hold all questions to the end of each session. We'll have a brief session following each presentation and then again at the end of our overall presentations. At that time, I'll also ask you to please wait for the microphone to make sure your questions are captured for the webcast.

I now like to turn it over to today's speakers for you to learn more about the optionality and flexibility and CRC's allocation process and also bestowed by a world-class resource base with its stock base and the tremendous portfolio of resource opportunities characterized by both conventional and unconventional as well as the multitude of drive mechanisms.

And now, I would like to welcome Todd Stevens to the Podium to tell you more about CRC's strategic focus. Todd?

Todd Stevens - *California Resources Corporation - President, CEO*

Thanks, Scott. Thanks, Scott. Is it on? Okay.

Good morning, everyone. I'm so glad to have you all here in Long Beach. Actually, we're standing on top of wellbore locations in the Wilmington field that are bottom hold underneath our current location in the city of Long Beach. So I give you an idea about Wilmington Field. You'll get to hear a lot more about it from Frank later on.

But what I wanted to talk about first is CRC and I'll give you a little context. Again, a lot of you have seen this slide and heard about it. But people forget and Scott emphasized this, California is world class oil and gas province.

Five of the largest fields ever discovered in North America are here. You're sitting on the third largest one ever discovered in North America. We will position in four of them.

At yearend 2014, we had approximately 768 million barrels proved reserves. If you take that into account and you take away the SEC five-year rule on PUDs, you have closer to a billion barrels if you put PUD equivalence to give you an idea of the context of long live nature of our reserves.

I think if you look at the right map on this slide, it gives you an idea about how the basins in California extend from the very northern part of the state in Sacramento Basin all the way down to where we sit in the Los Angeles Basin with the most prolific basin being the San Joaquin Basin in the middle part of the state which you'll get to visit tomorrow.

The one thing I will point out again, the middle part of the state is Kern County, a lot of people think about oil and gas provinces in the U.S. It is the largest oil-and-gas-producing county - oil-producing county in the Lower 48 Contiguous United States still today. It's speed up by the county in the North Slope in Alaska at this point in time.

We'll talk more about the capital structure in a little bit which is arguably the real issue with CRC when you think about the amount of debt we were given in different place environment. And we'll also talk about why we're positioned to work through that and excel and really do well for our shareholders throughout the cycle and this has to do with our huge amount of operating flexibility on all of our 137 fields, low decline rates in our assets and our crude mix increasing and our - ultimately our margins getting better over time.

This gives you a little bit a geographic breakdown of CRC upper-right hand corner, breaks it's down by the four major producing basins. We talked about the San Joaquin Basin being the most prolific part of what we do. It's about 70% of our reserves in production in inventory.

LA Basin where we're sitting today significant part of it in the Wilmington Field is our biggest part of that. Ventura Basin, the oldest producing basin in California but also one that probably as Scott alluded to the land that time forgot how California was discovered and also neglected over time. Probably the most opportunity underlies at Ventura Basin when you think about it from an oil and place perspective.

The Sacramento Basin is really a dry gas basin. Huge amount of contingent resource from a gas perspective but in $2.50 gas environment, not something that you're going to spend a lot of time on more than just understanding what happens in a slightly higher oil and gas environment.

Another thing I'll point in this slide is right here where you talk about mineral acreage position, 2.3 net million net acres, some of you are saying 2.4. Obviously, we'd let some lease hold go that we feel it's not its perspective in this timeframe. But again, 60% of that is held in fee and we'll talk a little bit later about what that really means economically relative to other peers.

Again, we talked about optionality and flexibility and operational flexibility in the portfolio. This is driving by all the fields we're in but also the stock pay nature of California and the multiple drive mechanisms that you can see.

You can have everything from dry gas to heavy oil and everything in between in this state and in some cases in the same wellbore, you can do bunch of different drive mechanisms.

Again, focusing on the amount of resource ultimately down here, the PV-10 again using that same methodology taking away the five-year SEC rule on PUDs will be closer to $20 million yearend 2014 and this is the snapshot of breakdown geographically a production for the San Joaquin Basin and the major basins in the United States - in California, sorry.

But if you want to understand California, you really have to understand its history to understand why it sits where it does today. And why you're seeing this kind of chart and you know that the top three producers are ourselves, Chevron, and Aera, Aera being the joint venture between Shell and Exxon.

That's about 75%, 76% of the production in few month built to top five. You're going to get around 85%, 86% of the production in the state depending on how you round. And this is really interesting because you think about most of these major multi-billion barrel oil fields were discovered in California in the late 1800s, early 1900s and probably the latest one discovered was here in Wilmington and that was in the early 1930s.

So when you look at these fields, they were discovered by the super majors and the super majors have or historically controlled California and not just all the fields but almost all of the acreage. And what happened over time in the statement was as they sort of producing, they got into the 1950s and 1960s, you know, the advent steamflood technology which Vic Ziegler will talk about tomorrow and so with Jeff Hatlen.

And these are - this is something where people started realizing they get 60 to 70 plus percent recovery factors from these fields and they started really focusing on that technology. So what happened was they started realizing the surface might be - was more and then they also started going in the '70s overseas chasing production sharing agreements overseas.

So in their worldwide portfolio, these assets in California really had a fair may of neglect and they sort of divesting them. In some cases, it was to mom-and-pop; in some cases, it was smaller independence but most cases, it was just people pleased to buy assets from a super major because they felt like they can probably melt them for cash flow..

So what you saw was that [exits] occurred generally where the majors retreated to the big huge fields that were steamfloods in most cases in the San Joaquin Basin and in some cases, you know, they stayed in some of the other ones.

But what happed was you saw them go to people who weren't going to invest in technology, they weren't going to invest in things that they're going to expand the reservoir whether be vertically or aerially, they were going to invest in just milking the cash flow out of the business.

So you had these exits by the majors that really ended in the early 1990s but every now and then you'll see the big players like Chevron or Aera saw little tiny pieces or lease out pieces of assets in the state. But you can see really quick, this is only 25 producers, 97% of the product of the state is in 25 producers.

There's only 330 registered producers as operators in the state. I'll give you context, Permian Basin has about 3,300 different operators in the Permian Basin and to get to 97%, you'll be struggling to do that with, you know, 300 let alone, you know, 3,000 there.

But this also the context on what's going on in the state. We talked about Chevron and Aera, the two players, they really focused on their steamfloods and they manage their declines and they don't invest in a lot of things. In some cases, they don't have the opportunity to invest because they divested those assets.

But the one last thing I'll point out on this page is most of the perspective minerals that are outside the producing assets rely in these three folks hands right here. So you can say this is maybe 75%, 76% of the production but it's probably 95% of the perspective minerals in the state and that's another reason why you haven't seen a lot of people try to enter and get in to the state because you can't get a position that's meaningful for anyone and trust me over time there's been a lot of major players come in and try to think about getting major positions and they just can't get the acreage to make it critical mass.

I'll talk briefly about capital structure and spend a little bit of time here. As most of you know, with the Moody's downgrade, with [spring lean] came into effect and we effectively went to borrowing base- secured borrowing base and that's has 90 days. We have delivered reserve report at 120 days which puts us into the first quarter of next year as one would come into place.

I think the important things to understand here is if you read the detailed, the Moody's report you saw and then probably the confidential information from the company that they felt like there will be absolutely no change in liquidity for the company going forward from that standpoint.

But one thing I will say in this context is we're actively looking to negotiate and work with the banks on an amendment to help preserve and help us facilitate all of our deleveraging events with regard to our assets and all the joint ventures we're looking to pursue on the development and exploration side too in the context to this and if you have any questions about that, Mark is available to talk about it but I think that that's something we're actively pursuing at this point in time, we feel really good about always sitting in that point.

But as most of you are aware of our capital structure, a lot of you are involved in the capital structure in some way whether be the debt and equity, you understand the $5 billion in bonds and then the credit facility with the banks. I think what's important here is to know that the bonds, there's no maturities until 2019 or later and the credit facility with the banks, we have to end to 2016 with our credit amendment originally that we did in February to do something there.

And we feel very good about where we're sitting with the deleveraging and I'll talk more about that in a second with regards to doing something to raise proceeds of up to $1.5 billion, $1.6 billion.

And you'll hear from Carlos right after me talk a little bit about the marketing regime in California and how we sell our hydrocarbons but also about how we've been opportunistic layering in hedges coming out of the bottomless cycle and you'll get an update of where we sit today with regards to that.

Really I wanted to talk through a lot of the issues and first, we'll talk about what happened. We spun off into - I want to talk about hurricane, you know, the Monday after the Friday of Thanksgiving where OPEC, I think they got someone called and they note this morning Black Friday for OPEC when they didn't cut production.

So it was not the ideal time to get spun off but that was the time we did. We'll talk about what we've been doing and really our priorities inside the company and what's under our control to take advantage of at this point in time.

As a management team and as employee base, I feel like it's not been perfect but it's been very, very good our response to what we've done and what's under our control, what we can do. We've worked on the balance sheet. We immediately pulled back capital as most of you know.

We had over 27 rigs working last November. By yearend, we had six. We had three working this year. We're committed to living within cash flow. We had that flexibility. I know some people were very skeptical based on our capital and our capital program and talking about flat production and the like and living within cash flow.

And, yes, if product prices somehow went to 80, we're still a little bit in cash flow. That is a basic premise of how we want to operate as a company. But one of the things that we've talked about doing when we're getting spun off of OXY is we wanted to focus, we wanted to be focused as a company, focus on the things that matter and we talked about how we were changing things going forward and how we're going to allocate capital differently as smaller more entrepreneurial more nimble organization and how are we going to engage locally with the communities we live and operate in.

And really, you'll hear a lot in a second but hopefully you'll also hear from all of the other people how internally what we do is we focus on the base, we focus on protecting our margins. I call it defending our margins and also the base production is important.

And we just recently restructured the organization for really as we talk about how we allocated our financial capital using our VCI metric, we're now allocating our human capital really focused whether you're on the base or you're on growth opportunities within the base or outside the base.

So we're trying to really focus our people on the value adds going forward. We have been aligning our cost for the current environment. I know you guys have talked and seen slides about our operating cost, bring your capital cost down.

We've taken actions recently that has brought down our head count and we feel like when that's all worked this way through the system, it will be about $1 per BOE reduction in our G&A. Just to give you scale, at spin off, we had approximately 2,000 employees. When this is finished, it will be approximately 1,700 employees when we're all set and done here.

Talk about deleveraging, you've seen this slide before, I think the important thing here is to know we cast the net foreign wide. I don't think there's anything we didn't consider or if there's a good idea that comes out even today, we'll consider.

But we're pretty far long a lot of opportunities here and I'll give you a little bit of the buckets in a second but I'll say if you want to get sports analogies, I'll really like to give sports or military analogies. You know, we're getting close to that part of the NBA game that gets interesting.

We're waiting the fourth quarter and the final drive under football and, you know, we're, you know, the Chase athletes taking out Tejada in the eighth inning of that, you know, and so it's waiting the game.

And so we're getting very close, we're not - you know, we're not talking about data rooms, we're not talking about site visits, we're talking about exchanging drafts to definitive documents and those types of things. So we're pretty far along.

And the other thing I'll focus on here and spend a little time here in a second is really VCI and how we allocate our money. As a small nimble entrepreneurially focused company, we have to allocate our capital and that's the most important thing a management team can do, you know, a capital intensive business, how you spend that money every year.

It's not going to reflect necessarily right away but over the long term whether you equate value or not, this will really shine through and we feel like using our VCI metric, it's absolutely critical and this is how we - we're very transparent up and down the organization in how we do this.

Talking about the different buckets of opportunities from a deleveraging standpoint, obviously, we're - on the upstream side, we're not in optimal situation, we're near the bottom of the cycle than we are near at the top of the cycle.

But the unique thing here is for years that from our parent, we [stiff] foreign people when they want to come in the state and be our partner and invest in properties whether be exploration, exploitation, all those different things. So now we actively are seeking partners. We want to bring that resource forward. We want to bring partners and want to bring capital to bear in the state.

And so we feel really good about where we sit with some potential JC partners on the development side. We're pursuing I'll say a few very large ones and a lot of small ones because we have a lot of potential partners and it's up and down the state. We're talking to folks even in the Sac Basin about partnerships.

But again, they're all different scale, different size. They could be very field specific, basin specific, different things like that but there's a lot of opportunities, a lot of interest in our assets and wanting to be our partner working in California and understanding that from that's standpoint.

Again, as you know, we have enormous acreage position, enormous seismic portfolio and all those things were important to understanding, you know, tectonically active basin.

The one thing we're pretty far along obviously is our midstream assets and I don't think people appreciate how much we have so we have a little list here so you can understand and you get to see at firsthand tomorrow at our fields. That's the largest mix of our infrastructure at Elk Hills.

You get to see the power plant, the processing plant and a lot of other opportunities that we have. This gives you a little bit of scale. We're actively pursuing numerous avenues here. Again, this market isn't as frothy as it was midyear I'll say but I think that the yield focused investors are still very interested in what we're doing and I feel like we're pretty far along here at numerous paths.

Some of them are mutually exclusive, some of them aren't. So we're trying to work what make sense for us both from a tax efficiency basis given that we're spun off and also from an operational control which is important going forward and how we operate these assets.

Capital market is - there's some opportunities there but I would out those at low priority at this point in time. We don't feel like that's the best use of or the best opportunity to delever at this point in time given the constraints we have in the company.

Protecting the base, what's important and it starts with how we would allocate capital and how we focus people. I talked earlier how we're focusing people on the base and we have said many times our natural decline with no downtimes around 10% and with downtime - historical downtimes as around 15%.

You'll hear people talk about today and tomorrow how they're focused on the base and refocusing on the base has really changed how we've been able to enhance this. And the thing to think about here when you talk about it is it's real money.

So if you just think about it just around numbers, 160,000 a day equivalent, if you have a 1% improvement in the decline rate, that's 1,600 a day. So if you use any kind of metric, let's just throw out 25,000 BOE per day, you know, as people like to use rules of thumb, that's $40 million that you've averted or not spent for the year.

But that number, you know, you could argue with that number higher or lower but if you went to the M&A market, it's probably going to be higher. But internally, it could be different but I've just given you an example. So it's real money focusing on the basis of importance but it starts really here and this is something we've changed internally and it's very transparent.

So if you went to a field operator who worked in any of our fields throughout California and they asked how we allocate capital, they'll be able to tell you exactly this formula right here because this is the kind of slide we share with them when we tell them it's not a black box, we're not chasing production, we're not chasing cash flow next year, we're creating value for our shareholders, the most value over the longer term using our VCI metric.

And this is really trying to balance it out being self-funding and we have enormous portfolio we can execute on but really the governor is how much cash flow we have to bear and that's really what we want to partners because partners can come in and out but accelerate things we might not been able to get to for four, five, six, seven years out in the future but this is something that ultimately measures how much bang for the buck we're going to get as a company.

You've seen a little bit of this inventory slide, I want to - and I - there's a little bit of a change and I want to give you some context. So this is something that are ready-to-go engineer projects that have a VCI greater than 1.3 which is the criteria for us to allocate them capital, a different pricing mechanism from 55 to 85 and then by drive mechanism and workovers.

You can't underestimate workovers. Those are the absolute highs VCI projects in the portfolio period and what does that mean because you don't have to put it in new wellbore, you don't have to spend a lot on facilities. Typically, you're just going back in and doing - going to a different zone or cleaning out a wellbore at that point in time.

But the different thing here to remember is it's a dynamic living breathing. This is changing and Frank has a great slide later talking about the Wilmington field, how it's a living breathing growing enterprise because what happens is human activity or drilling activity that begets more activity.

So if we study these fields, we typically come up with locations, we typically come up with inventory and what we want to do because most people think in rigs nowadays because of the shale model, we put down here on the bottom kind of the rig years. So if we talk about a phase of three rigs, how many rig years each one of this inventory has just for the drilling rig.

Because again we're not just about the drilling rig, you know, we're about the workover rig, we're about facilities and doing a lot of different things over time and really workover rigs ultimately going to add a lot more value. This is something typically you've seen in the super major and I know I've heard presentations by Exxon historically that they add more value here than anyone and I would argue that's probably true.

When you have an existing wellbore and you get some workover rig, you're going to add more value and then going out and spending the capital typically from a drilling rig.

This is a little bit of [barreled] and we used a lot of peers. This is ITG decline curve. But this goes to show and I think it's lots in some people is we have a best-in-class decline rate, a shallow decline.

What does that really mean when you have a shallow decline? It doesn't cost as much to keep you going. You're not on a capital treadmill. But more importantly, when you look at the context of capital in our peers like on Slide 19, you can see if we factor it downtime at a 15% corporate decline, this is according to Wood Mackenzie, sorry, the, you know, average peer decline is around 35%.

What this translates across the basins, you can see, you know, for a full cycle long term we feel like $600 million, $700 million to keep ourselves flat. You know, you can see some of these other very hot active basins what kind of capital intensity they're required to do the same.

This is something that I think people are now starting to appreciate in CRC but again we have to emphasize and talk to you about because again lower decline, capital intensity of our assets is unlike any others and again you'll see this in super majors are very large independence they have these types of assets.

And what does this translate into a very resilient production profile and because of our optionality in our portfolio, all the leverage we can pull, depending on the product price environment, we're going to do what makes the most sense and deliver the greatest VCI for our shareholders and right now that's steamflood and waterflood investments and that's going to be the topic of our conversation today and tomorrow talking really a lot about what we do there and how we create value there.

But you can see we've been able to do deliver in whole production fairly flat overtime and we have a huge amount of inventory as most of you know with regard to these types of assets and they continue to get bigger even in this price environment today.

This just gives you a little context, if you look at the top 10 fields and then by drive mechanisms, the one thing I'll just, you know, I will state this later, but one thing I'll tell you is, to give you an idea, all these bonds are expanding in a lot of these fields.

But Elk Hills five years ago was 60% of our production, now it's 37% of our production and it's declined but also a lot of the other fields have grown and that's from us studying them and doing the work and extending them vertically and aerially and we've given you a lot of examples historically Pleito Ranch and many others. But this is something that continues as we again bring the kind of focus we need to bring to all these different assets in California.

Defending our margins, something important because it's not just about costs, it's also about differentials and Carlos will talk about that in a little bit. But you've seen this slide before but what I wanted to do and this is our analyst day last, was it Halloween or the day before Halloween last year, but this gives you an idea.

Again irrespective of the commodity price cycle where we've seen on this graph, we have opportunities and we have a lot of inventory to execute. And you can argue that at this point in time, we're down here and you could see this is, you know, bottom left quadrant what are we executing today.

You can see a lot of these things right here, the type of things we're doing today, Mount Poso, Eastern SOZ and Elk Hills and that's done with compression, Kern Front Steamfloods, Long Beach Waterfloods and you'll get to hear a lot about this today and a lot of workovers.

But again, a lot of you know high gas price environment, we have a huge amount of contingent resources in the Sac Basin that we started talking about $3 gas, $4 gas and gets really interesting really quick that we sit on. This is just really prioritizing the portfolio and allocating capital in a high oil price, high gas price.

And again in this environment here, high oil price is lower natural gas prices. This is really a focus on steamfloods and a lot of our conventional and our waterfloods assets.

Again, this is meant to give some specific examples and each one of these parts of the cycle, things we can execute on that we're not just a one trip pony here. We have a lot of optionality and leverage to pull in our portfolio.

Again going back to what are we doing to defend our margins, I'll give you an idea, our cash flow at first half of 2014 was here. We've increased our volume. Price has come down but, you know, we've tried to mitigate that the best we can and how we market our hydrocarbons.

Our cost, we've taken cost out the system. Obviously, we didn't have interest expense back then and taxes have changed because of the less revenues. Working capital was something that happened. But this just gives you an idea again our focus on what matters, what we have under our control, that's what we're doing.

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Talking about our leasehold position, I hinted at this earlier, this just gives you context of California. There's, you know, we mostly are held in fee but again we have a small amount of leasehold that expires each year.

And because of the way it's held in California it's rare to have over 20% royalty. Typical royalties were anywhere from 12.5% to 20% and you're not going to have the huge bonuses. You're going to have to pay if you're going to acquire the Eagle Ford or the Permian. It's much different.

I'd ask you to probably ask Darren in this type of questions from what he have seen tomorrow morning in the Woodford and elsewhere in the country. It's not just the same type of thing that you're seeing when you talk about the scale and scope of royalty and bonus payments.

We're really trying to prepare our company obviously for change in the cycle. I think a lot of you are very interested in what happens in higher price environment here and like I've said, we will live within our means.

What does that mean? I mean, if you look back in '86, the collapse, you know, how long did it last, where are we tracking if we index the price declines? Is it going to be a few more years or for longer like [Bryans] friends think or is it, you know, can we really trust any of the curves out there?

As you know over time, this is actually what happened with Brent and this is what the curves have said over different price points in the cycle. So what we like to look at is say, okay, let's look at this on almost histogram type thing and say, okay, we have started to '95 to the present last 20 years.

This you can see is kind of pre-shale ample capacity in the system. And then you start getting into where you get over here the last five years or more than five years we have very tight spare capacity, you have a lot of geopolitical risks in the commodity.

We actually feel at CRC that it's going to settle somewhere in the '60s and, you know, we talked about how we're defending our margins, we really are planning our organization, we didn't say we want to cut this many folks, we want to get the organization, you know, these many heads.

What we did was we said, we think longer term the price is going to be in $60 Brent environment, this is WTI but $60 type environment, what does the organizational look like at that environment? What is the activity set in that environment?

Let's staffed ourselves for that. Let's not get into these arbitrary percentages or headcount number. Let's talk about what should we look like in that environment and do the right things for the company.

And then also borrowing from Brian's compatriots at Goldman, this is interesting slide because you look at the top 420 fields and what do they really need to work and I think it's very interesting as you start looking at this curve, you know, the pricing curve that really needs $70 oil to make a lot of these things work on this part of the curve.

Obviously, you're not going to need the super deep water ultradeep shelf stuff out here but you can talk about here where does it stand out and, you know, you can make that argument or even throw in some geopolitical resin and I get that really quick.

But it brings us back to California, that is stable environment as you'll see in the United States. We're world class oil and gas province. We've had over 35 billion barrels produced since 1876.

The first commercial oil well west of the rocky mountains was drilled in the eastern Ventura Basin in 1876 that produced all the way to 1992. That's the - that was actually the predecessor, the Chevron Corporation that was drilled by Charles Mentry.

But this is very prolific basin that has changed it and not made it basically ubiquitous through tectonics over time. That's why we have all these unique discrete basins that have all these different drive mechanisms because of tectonics.

Otherwise, you'll be sitting out here and talking about something identical to the Permian Basin because very similar type environment with stock - huge amounts of stock pay but here we've had this fault system and it's mostly you saw last night at dinner, you have the Newport-Inglewood Fault and if you've gotten to a lot of detail you'd see right away where the fields are and how they trend from the southeast to northwest.

And it's a similar part in California San Joaquin Basin was an inland ocean and deposition on environment there that occurred over millions of years. But this is something that, you know, we're very excited about and we have a large amount of underexplored, underexploited opportunity set.

But what is the real opportunity set? It's really oil in place and every time we study and I encourage you to talk to any of our people, it just gets better and the oil in place is far understated the most cases because modern technology hasn't really brought to bear.

Currently, based on estimates, we think there's 40 billion in place originally from what we have and we're about 22% recovery. But a lot of technology has been brought to bear until really Occidental and now CRC came to put it in place here in California.

To give you an idea, you won't find anywhere elsewhere out of 137 fields, 94 still on primary production. Natural energy in the reservoir, gravity drainage, that just doesn't happen. And to give you an idea and you'll hear a lot more about this later but you can get - primary production, you get 10%, 20% maybe depending how good the rocks are. You know, double that in waterflood.

Steamfloods, you're going to get up to 70% recovery. These are all things as we look at, we want to migrate these primary fields to secondary and tertiary recovery and why do we have this excellent opportunity set is because there's huge amount of stock pay.

Elk Hills alone and you'll hear Bob talk about this tomorrow, 2,000 to 12,000 feet, we have wellbores producing, from 2,000 to 12,000 and everywhere in between. And this is - that's just an example of a microcosm what's happening at all of our fields.

And as we look to delineate, in 2009, we had a discovery going deeper inside the Elk Hills field essentially after the [flanks]. You know, this is something that 3D and ultimately good geology using wellbores and modern logs has enable us to go back and work on.

And this really tells a story of technology in California, what went on, I mean, back here in the early 1900s, late 1800s, that was drilled on, you know, surface, expressions, sips, the easy things were done and they found billion barrel or hundreds of millions of barrel fields.

But over time, things changed. It wasn't until here where you really start talking about 3D and no one really shot 3D in California until we came in and we started shooting 3D. Chevron shoots 3D at current [lever] but they do as part of the 40 seismic program but there aren't a lot of 3D shot.

There isn't a lot of modern logging, image logs, those kinds of things. They've really made a big difference as we look at how we delineate these fields and how we better exploit these mature oil fields that have enormous amount of stock pay and enormous amount of upside potential and then tomorrow you'll hear about how we can explore, I mean, Darren will tell you he doesn't feel there's a place like this in the world that really is like California from an exploration standpoint from untapped potential.

Coming back to the beginning, huge amount of inventory broken down by basin. A lot of liquids rich except for the Sacramento Basin which is gas. This gives you an idea again locations, we think about VCI, you know, these locations down here could have just one VCI, they could be a 10% rate return project but they're trying to compete to get moved up the portfolio at this point in time.

I think when you think about CRC, you have to appreciate the sheer scale and scope of our operations and the breadth and depth of our operations and the amount of operational control we have that's unparalleled and how we can pull all those levers. And whether you really believe in lower for longer or, you know, we're going to have higher oil prices next, you know, quarter or something, I think you won't find a better opportunity for investors really to get exposure to oil prices.

I don't think you'd be here if you didn't believe that, you know, those supply-demand imbalances going to work itself out over time and in oil prices will rebound to some level, just a question what level that will be.

We at CRC, we're committed to living within our cash flows. We're going to use our VCI metric to create value for our shareholders. I think you'll hear from everyone how focused we are on being entrepreneurial in executing things that make sense for our shareholders over the longer term and I'm glad to take any questions at this point in time.

Yes, sir, Doug right here. Okay.

Doug Leggate - *Bank of America - Analyst*

(Inaudible -- microphone inaccessible).

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. Go ahead. We'll bring the mike up to you. Right here. I'll repeat it if it's not working. Okay.

Doug Leggate - *Bank of America - Analyst*

Thanks, Todd. Doug Leggate from Bank of America. So perhaps the most significant issue that I took from your remarks, Todd, is that you're at the point of exchanging definitive contracts now on some of these disposal prospects.

So can you give us an update on first of all, expected timing being able to tell the market and secondly, what you're targeting by way of proceeds as the idea to get your debt, your revolver, and your term loan to be done or do you want to go beyond that given your [two times] EBITDA target and the fact that your debt is still trading at $0.70?

Todd Stevens - *California Resources Corporation - President, CEO*

You know, I think in the midterm as we said or short term, medium term ended 2016, we want to raise $1.5 billion, $1.6 billion and, you know, that's ties obviously to what we have outstanding under the term loan on the credit facility.

But if you - you could say we're just going to pay that down but the reality is once you get the proceeds, you have to do what makes the most sense. So it's an intellectual discussion now but if our debt still trades, you know, where it trades today, you have a different discussion but it trades up into the 90s and we have the proceeds, it's a different discussion to have at that point in time.

We have to do what makes the most sense for the shareholders at that point in time and we talked about timing, I still feel very good, we're going to have one or two sign up by yearend, if not, close. I think that we could have more, you know, - could, you know, slip from a layering up standpoint into the first quarter. But at this point in time based on what the line of sight I see, I think there's a very good chance about one or two sign up, if not, you know, one or two close by yearend.

Doug Leggate - *Bank of America - Analyst*

If I may follow up this with clarification, so the upstream joint venture opportunities, are those about bringing proceeds end or about securing growth through someone else's balance sheet?

Todd Stevens - *California Resources Corporation - President, CEO*

So I think and again that's part of when I talked about all those leverages you can pull, you have - some of them you have mutual exclusives, some of them weren't. We don't need to raise a ton of proceeds.

So when I think about it and I said, okay, if I can get enough proceeds out of the midstream assets, I have probably want my upstream joint venture to be really focused on the drill bit and get more carry at that point in time because we have so much value to be able to create even in this price environment, we like to be able to put more into the ground. So I think that that's an opportunity because you don't need more proceeds upfront from that standpoint.

Another question we have over here. Yes, sir?

Unidentified Audience Member

When you think about your portfolio, how do you think about sanctioning each sort of if you put it buckets, right, so your conventional steamflood, waterflood, what sort of the price internally do you guys think about to sanction these things? And I know you have your own internal metrics as well but [frame across on that], that would be helpful.

Todd Stevens - *California Resources Corporation - President, CEO*

Well, some of you at dinner met Francisco, he keeps our entire portfolio, our inventory and effectively the way we look at it at any point in time is based on the strip, you know, because anything else you can be fooling yourself or we like to, you know, iterate off that.

So you'll say, okay, this is the [strip], if we take five bucks below, we hold it flat, we take five bucks above, we hold it flat, what does it look like. And then, you know, you're going to high grade of your VCI metric and then you start taking into account, you know, let's say all these ones have greater than 1.3, what's the best use of proceeds for an operational standpoint, rig moves, those types of things but that's really how we do it.

As you take the start over the strip and usually we're going to move off that a little bit probably lower and try to see, okay, prices hold flat here, where do we sit. But that's really, you know, if you want to say it how we look at it.

Unidentified Audience Member

So if you got - if I understood correctly, one of the slides was your new normal and you guys are sort of planning for maybe 60 to 70, I don't know how long before but let's just say that's the new normal, what sort of falls underneath that in terms of being sanctioned the conventional obviously and the workovers would?

Todd Stevens - *California Resources Corporation - President, CEO*

I think if you talk about mid-60s, everything is going to have a VCI of 1.3, not everything but most everything, even some of the unconventional opportunities. But then you're just high grading based on your cash flows at that point in time.

So really given that new normal was how we restructure the organization because I've been through a few cycles where you cut too deep and you hire people back or you - or they change and leave the industry. So from my perspective, we want to make it so that also we anticipate success in some of these joint ventures that's going to create activity so we need to have the folks in place to help us execute that. We don't want to cut to the bone at this point in time.

Unidentified Audience Member

And last question, on the upstream side, the asset sales that you're targeting or the cash and carries I should say, is this purely on what's existing production day or is this bringing in 2P into the equation like how do we sort of frame it?

Todd Stevens - *California Resources Corporation - President, CEO*

I guess all of the above.

Unidentified Audience Member

Okay.

Todd Stevens - *California Resources Corporation - President, CEO*

I think there's not - there's really no I'll say existing production but it's all the above after that anywhere from PUDs, 2Ps, 3Ps type opportunity including exploration opportunities where talking to people about.

Yes, sir?

Unidentified Audience Member

(Inaudible -- microphone inaccessible) ability to sell assets and might have collateral pledge into that revolver?

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. Yes. The question really is about the revolver and what happens with the [spring lean], is that what it is?

Unidentified Audience Member

Yes.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. Mark, you want to address that? He's in the midst of this right now so executing on it.

Mark Smith - *California Resources Corporation - CFO*

So the question relates to the revolver, how it may restrict this in the current environment. As Todd alluded, we have the - we have a current a current spring lean situation, we have 60 days in between the process of providing security to the banks.

We have a period of 90 days where we provide an updated reserve for it, all that is ongoing. As Todd indicated, we're well advanced with respect to some of our various deleveraging initiatives. So we're in the process of having ongoing dialogue with the banks about what that might look like and we're taking a deep dive into the credit agreement to make sure that the banks are updated with respect to what we're thinking about and how that - how we might need to modify the credit agreement to accommodate that.

So we're well advanced having discussions with not only our lead bank but, you know, our style is to have a good ongoing dialogue with all of our primary banks and they're very supportive, the discussions are going well.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Mark Smith - *California Resources Corporation - CFO*

There's flexibility under what - as to what we put into the borrowing base, as to what we pledge and those assets that we actually pledge [didn't] subsequently drive the borrowing base.

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. The midstream assets aren't involved.

Mark Smith - *California Resources Corporation - CFO*

Yes. So classically what you'll lose, you'll put your, you know, producing E&P assets into the reserve report that then drive your borrowing base and you'd leave, you know, your midstream assets outside of that.

Todd Stevens - *California Resources Corporation - President, CEO*

I think Brian has a question up here.

Unidentified Audience Member

Thanks, Todd. For those who want to base case $1.5 billion in asset sale proceeds coming in, should we expect any kind of corresponding impact in the cost structure, i.e., higher cost structure as a result of assets like the midstream and if so, how would that roughly impact the breakeven prices to achieve your VCI goals that you talked about through your inventory?

Todd Stevens - *California Resources Corporation - President, CEO*

I think it's - Bob will talk a lot about just Elk Hills infrastructure tomorrow. When you think about - we are going to be on the midstream side in particular taking a little bit of income statement leverage and bringing in the balance sheet.

I'll say all the ones we're contemplating or we're talking down are accretive to us in some fashion. So the way it will work is, yes, you have a little bit but I don't think in the context of everything we're doing particularly with the initiatives we've had underway from a cost cutting both in the operating cost and capital and in - for an overhead, I think we're more going to be able to capture that over time any amount that we might layer on there from a cost perspective.

I mean, the one thing I think people forget, the sure amount of infrastructure we have, I don't think they will appreciate it. You'll appreciate it tomorrow when you see some of it firsthand is, you know, to replicate that would be pretty impossible and the sure amount of dollars, Bob, it's - what we figured out is would cost someone to third party just in our northern operations in san Joaquin Valley, it's what $200 million a year, you know, or so. You have to pay a third party to do so to give you an idea that's the scale of that.

[Kevin], yes? Brian passed it down there. Thanks.

Unidentified Audience Member

Greath. Thank you. Maybe somewhat of a followup on that question, I mean, how do we - you know, how do you think about accretion or dilution of these asset sales, you know, on an after tax basis?

I mean, given that they're most likely diluted on your current valuation. You know, you're looking at it on your new normal commodity price scenario where you're selling EBITDA and how that sale relates to your current valuation?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes, I mean, you have to, right? You have to look at that and see, you know, perfect scenario, you don't want to do anything here. You like to preserve that flexibility for yourself but we're in a situation where we feel like we have to do something and this is the best alternative for us at this point in time.

We think there will be some - it will be accretive to the valuation because of the valuation will get relative to how we trade. But, yes, again it will [take] us a little bit on the EBITDA but we feel like we'll get - we think it paid for that upfront a little bit more relative to our valuation.

Unidentified Audience Member

You mean these accretive figure asset sales will be at a premium to your valuation in the marketplace?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes all of them will be, yes.

Unidentified Audience Member

Okay.

Welles Fitzpatrick - *Johnson Rice - Analyst*

Good morning. Welles Fitzpatrick from Johnson Rice. On the inventory slide on 17, is it fair to think of somewhere between the kind of three to five rig phases as being what you need to stay flat? And if we saw substantial move higher in crude pricing, would you use that more quickly accelerate into your debt or to pay down debt?

Todd Stevens - *California Resources Corporation - President, CEO*

I think if you saw a roundup in prices let's say some geopolitical event occurred, I think we would have a propensity to want to paydown debt first but I will say 75-25, you know, of those excess cash proceeds if that was the case where, you know, we had someone bumped somebody and, you know, it ran up to 90 all of a sudden, I think that would be the case in that scenario.

But when you look at the inventory, the rigs are really a function of, you know, the different projects. So some of those are very shallow steamflood type wells where you can drill, you know, 20 of them a month, you know, in some cases. But they're all different and so the rig is going to change depending on what type of opportunities you chase.

If you're using a medium rig in a different basin or in a different part of the San Joaquin Basin and other doing steamfloods that's going to - you'll only get to drill a few wells in a month under that environment.

Okay. We get the last question and we can go on to the next - going to Carlos. [John]?

Unidentified Audience Member

(Inaudible -- inaccessible microphone) primarily conventional or unconventional or they spend the gamut?

Todd Stevens - *California Resources Corporation - President, CEO*

Spend the gamut really at this point in time. We were talking to folks about every type of drive mechanism and also unconventional and conventional at this point in time.

All right. Carlos, I'll turn it over to you.

Carlos Contreras - *California Resources Corporation - VP - Commercial*

Well, thank you, Todd. My name is Carlos Contreras for those of you I didn't get an opportunity to say hello to you last night and as Todd likes to say, you know, our job here is to defend the margin.

My piece of that is the commercial component of the organization and that's made up of the marketing and trading group and our supply chain organization. But for today's purposes, I'm going to focus around the marketing component.

So some key takeaways that I want you all to think about and you'll as these themes keep coming through the course of the presentation is because of isolating factors such as infrastructure and, you know, the sources of our crude being the waterborne crudes, we tend to follow a Brent benchmark in that spread between WTI and Brent.

As far as natural gas is concerned, we're the largest producer of natural gas in the state. We market natural gas not only throughout the state but at times are opportunistic and we're able to move the gas outside of the state to capture some premiums as well. And with respect to the NGLs we're the 800-pound gorilla and I'll talk a little bit more about that in some of the subsequent slides.

So this picture kind of says it all right and Todd talked about this to some earlier, you know, the land that time forgot and you can just see here, you know, in this map that California is an island. And so, you know, as far as interstate pipelines, there are no interstate pipelines coming in and out of the State of California and rail is really one directional.

About the - of all the crude that's processed in the State of California, 65% of the crude is imported into California, 10% of that crude comes from ANS since the [last] crude and 55% is imported from outside the United States and some of the top importers are depicted up here in the upper right-hand of this slide.

Another key piece to takeaway of California is that the California crude, the average API is 18 API and you can see the difference here with the imported barrels and I'll talk a little bit more about the API component in the subsequent slide.

This is - so Todd talked a little bit about the cards we dealt, you know, we spun off and we see a low commodity priced environment and you can see the effects of that of the low commodity price on our realized prices. We are hit additionally with a couple of discrete events which Todd and others have talked about on our earnings calls.

And so we're working very diligently to work through these, you know, lingering effects of those discrete events and expect, you know, to come through in the coming months. As far as, you know, where does our crude go? So about 56% of our crude moves to Los Angeles Bay Area refineries, about 40% of our crude moves up North to the San Francisco Bay Area refineries and about 6% of the crude stays locally in Bakersfield.

You know, you recently heard, many of you probably saw the recent announcement of PBF Energy's acquisition of the Torrance refinery from ExxonMobil. That refinery was made like many of the other refineries that you see here to run heavier crudes, California grade crudes.

And we've already had some initial conversations with them, that refinery sits in that, you know, that 16 to 19 API range and just straight down our fair wave had some initial conversations with them about, you know, growing that relationship.

This is just another way of kind of looking at looking at California. Todd talked a little bit earlier about of how we contribute to the red here which would be the California production. And so while, you know, Chevron and Aera's production has, you know, continued to decline, CRC's production has increased.

You also see the big effect and the big impact here at the waterborne crudes and again we go back to how we tend to be more closely tied to which is that benchmark. And then the last thing that I'll put up here because I've gotten a lot of questions about this in the past is the crude by rail and the effects of crude by rail and you can really see that that effect is absolutely minimal.

So again, touching on crude by rail, if that crude were to land in California, you're really looking at $12 to $15 discount to come in to California because of the effects of transportation. Again, the scales here make this look a little bit bigger than it is but the effects are minimal.

There are many projects that others are talking about but I think to really look at two components, one being the commercial component and the other being the regulatory and permitting component. We don't see really many of those projects actually coming in to play.

The plains terminal would be the one that more closely - we track more closely and again the effects are minimal at the throughput and deficiency agreement that's there for that terminal has been taken up by the refiners and a lot of time people tend to focus on the Bakken and they're saying the Bakken crudes come in to California, very little of that is coming in but what you really see is that Canadian crude is coming in.

So Todd mentioned we need to be opportunistic in our hedging strategy. Our target is to try and get to a 50% range of our production and obviously, you know, that's our target. It doesn't necessarily mean that we're going to get there.

And what do we mean by being opportunistic? We try to hedge the largest possible volume at the lower possible cost and we do this, you know, to protect our cash flow and to be able to sustain our capital investments. So again this gives you a little bit of an idea of the fairway and where we're playing just from the perspective of our weighted average of our hedges that are put in place here.

As far as natural gas market in California, California imports 90% of the natural gas that's consumed in the state. We move- and predominantly that gas is coming in from the Rockies, some is coming in from Canada and the southwest.

We produced just under 40% of all thee gas produced in the State of California and that we market the vast majority of our gas in Southern California although our Sac Valley production that Todd mentioned earlier, that gas stays up in Northern California.

And we are opportunistic and we do have the opportunity to have both forward hole and back hole for our gas and we're able to pick up, you know, premiums on our gas at the Pacific Times.

So this is just another way of looking at SoCal boarder basis versus NYMEX. So when you see the red is the when NYMEX is stronger than SoCal boarder basis and the green being those times where, you know, the SoCal boarder basis takes a premium.

I guess the key takeaways here increase the factors that are going to impact this, it going to be increased production so shale production, Marcellus production. The effects of weather, so stronger winter in the West - in the East, milder winters our here in the West.

And then also the growth of the Mexican demand and that demand where we're seeing not only from a natural gas perspective and the potential premiums that we'll see here in Southern California but also for the NGLs and we'll talk more about here in the subsequent slide.

So from our hedging perspective, we believe we're hedged at about 120,000 a day. That's 60,000 a day that goes to our thermal operations so we view that as naturally hedged and then 60,000 a day that we did in combination of the fixed price swap and the [cost's color].

So far as natural gas liquids, Todd alluded to this earlier, just from our facilities out of our fields and you'll have an opportunity to see it, we're already 800-pound gorilla. We process 63% of the NGLs that are not processed through our refinery and we market about 70% of all NGLs marketed in the State of California.

We do this by not just marketing inside California. We moved our natural gasoline to Canada that's uses as a diluent for the crude up there. We moved our butane to the Bay Area refineries and our propane is moving down in the Mexico but obviously also sold in California.

If you were to look at a map at the United States and you would be able to see that second highest posted prices for propane in the United States is in Bakersfield. Our posted price today went to $0.68.

We've seen an increase in our posted price over the last two weeks of about 17% and over the last six weeks of about 34%. Again, we do this by moving our NGLs by rail, by truck and by pipeline.

And so again, that just takes me to a quick summary of where we were. Again, we look at the isolating factors. You were able to see that California is an island. You were able to see kind of how we track from realized price with respect to Brent and that Brent WTI spread.

You can see that from both the NGL and the natural gas perspective, we're the 800-pouhd gorilla and the things that we're trying to do in the markets that we're going to be chasing in the future. So next, I'll be followed by Charlie Weiss but I'll be happy to take any questions that anyone has. Please.

Unidentified Audience Member

(Inaudible -- inaccessible microphone).

Carlos Contreras - *California Resources Corporation - VP - Commercial*

We're not - we don't process ethane out of the Bakken that [CGP] wants so nothing.

Unidentified Audience Member

And then on just a followup --

Carlos Contreras - *California Resources Corporation - VP - Commercial*

Chevron had offered to sell us I think.

Unidentified Audience Member

Okay. How sustainable is that propane price advantage because it's, you know, that's different from what a lot of other producers in the U.S. are getting? That's 16 - you talked about $.68. Do you feel like a good visibility on sustaining that?

Carlos Contreras - *California Resources Corporation - VP - Commercial*

I think we do. I think we do. I think we've got long-term relationships with our Mexican partners that we've sold to since the days of OXY. I think that one of the interesting things that you'll see is, you know, the Mexican market was supposed to open here on January 1st and there is some delays there and Pemex kind of pulled back on the strings a little bit and so we expect that delay to really be a year but that market should firm up and that's basically the feedback we're getting from our partners down south so.

Unidentified Audience Member

You talked a lot about your crude being Brent linked.

Carlos Contreras - *California Resources Corporation - VP - Commercial*

Yes.

Unidentified Audience Member

You know, I think one of the things that like the refineries have talked about is trying to create or make California more competitive by bringing additional crude sources here.

Have you guys looked at what that impact might be for you guys over that causing you doing more TI links just kind of giving the API gravity or can you talk a little bit how you guys see that kind of progressing given sort of their plans?

Carlos Contreras - *California Resources Corporation - VP - Commercial*

Sorry, just so I understand the question, you're really talking about that TI Brent linkage and by bringing in additional crude whether we would be more tied to WTI, is that correct?

Unidentified Audience Member

Correct. Yes.

Carlos Contreras - *California Resources Corporation - VP - Commercial*

Well, so I think we're a little bit more limited there because - from that happening because that vast majority of crude, we have to come in by rail, I just don't think the facilities are there today and again, those waterborne markets tend to be closer tied to Brent. So I'd see that us maintaining that position closer to Brent-based market as opposed to WTI in the future.

Okay. Thank you all.

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Good morning and thank you again for coming out to speak with us today. I'm Charlie Weiss, I serve as EVP of Public Affairs for California Resources and essentially within my purview is health safety and environmental programs, class or community and regulatory outreach.

I'm going to talk this morning about really our four key attributes that distinguished CRC as an independent California company. The first is operational excellence and you'll hear a lot about that from Frank Komin and Bob Barnes and as you've seen for yourself our operations.

Second is really our thoughtful planning. Todd mentioned Francisco Leon who's the Director of Planning, that comes back to our VCI metrics and the way the we stage and plan our jobs and also affects our regulatory oversight and the way that we pursue permits.

Third, our sustained outreach. We are very committed as you'll hear to working with the state and our communities. And finally really is our commitment to helping the state solve some of its key economic and environmental challenges.

And what we find is that really the state political business and labor leaders and a growing segment of the population recognized the essential contribution CRC is making to the state and local communities in the form of affordable reliable energy, good paying jobs, substantial royalties and taxes, and our role as a net water supplier to agriculture.

And this morning, I'll talk a little more about how we apply those attributes to grow our business and also the trend we see in state and local agencies pursuing a more predictable permitting pathway and process.

CRC's core values of character responsibility and commitment are really reflected most directly in our proven track record as the operator of choice in sensitive coastal, urban and agricultural environments and is the leading operator on state lands.

And the pictures on Slide 52 show here on the upper left Island Grissom which many of you will visit today, there is many award-winning design features and it's one of our four oil production islands in Long Beach Harbor. And the lower left, that's the Huntington Beach Field situated between the Pacific Coast Highway, prime residential neighborhoods and the Bolsa Chica Ecological Preserve.

On the lower right platform Emmy, that's CRC's only offshore platform. It's 1.3 miles offshore Huntington Beach. Whether we're in a big city harbor or remote location, we design and maintain our facilities with our neighbors and our communities and the environment in mind.

The other attributes in how our core values really show through what we do is in our constructive participation in the state's development of legislation, regulation, and energy policy to address key challenges like the draught and to streamline the permitting process.

And we're very proud of our success in building diverse coalitions with business, agriculture, labor and community stakeholders who share a common interest in reducing California's exposure to imported energy from the Middle East and other locations and to achieving the benefits economically and environmentally of local energy production.

The key pressing issue in the state today remains the draught and we're committed to supporting all efforts to alleviate that and we're playing a very constructive role in that. As you can see from Slide 53, only about 4% of our water that we handle is fresh water.

And just to put that in some perspective, essentially, we have been working to conserve and recycle water effectively for many years well before the draught became a public focus and that's had a big positive effect. To put water use into perspective, really the state's Department of Water Resources has indicated that less than one quarter of 1% of the fresh water applied in the state 2010 was used for energy production.

Two hundred times that amount, about 48% of the state's water supply was used for environmental habitat, 41% was used for California's agriculture industry to supply food worldwide, and 11% was used for urban use. So even though we have a very low water footprint on freshwater, we're very committed to conservation and we also have a great opportunity to help the state because we handle produced water and we are looking for ways to recycle and reuse that and we've done that very successfully in 2014. We recycled well over three quarters of our produced water directly in our improved and enhanced dual recovery operations.

And more importantly we supplied over two billion gallons of treated reclaimed water for California's agriculture industry. And that's water that water that wouldn't otherwise be in the equation and is particularly valued in the San Joaquin Valley where farmers who've had their other irrigation sources curtail.

So, we are very committed going forward to be a contributor on this issue and, in fact, we've partnered recently with another water district that will substantially expand our role as a net water supplier in California.

One example I wanted to share with you of our water conservation is in Long Beach. We already recycled 99% of the water. It comes either from our own recycling or from the cities partially treated municipal water.

So, we have a very small water footprint, but this year, we've invested in reducing that further with a new lube oil cooling system which will cut our water further in half by the end of the year. And so by next year, the long beach really fresh water use will be limited to our power plant, our island landscaping that's specified by the city. And finally, by our own workforce, just domestic water use.

As I mentioned, the state has focused on really revising its regulatory system for allocating surface and ground water and they're going to be doing that over the next few years as well as pursuing actively more recycling and reclamation of water as opposed to disposal and we participate actively with state agencies and water districts in these efforts bother through our own team of hydrogeologist and engineers and through our coalitions with business, agriculture, labor, and community groups.

And I'm very pleased to report that despite the state's water conservation order which have curtailed a lot of users, we have not had our water supplies or our oil natural gas or electricity production curtailed to date by those water conservation orders or by the state's review of underground injection or water reclamation.

And our efforts to recycle and reclaim more water and our conservation efforts are really benefitted by -- and we're given great flexibility because as Todd said, we have such a tremendous scale of our oil and gas operations with multiple drive mechanisms. We have a high degree of operational control over our 137 fields, we have a permitted network of injection wells that are far away from public water systems and we have a sizeable acreage position.

We've talked in the past about well stimulation regulations, SP4 in California and I'm pleased to report that we're seeing after a two-year thorough set of studies and regulations that California now has finalized, really what are the most comprehensive regulations for hydraulic fracturing and well stimulation in the country and we work closely with the agencies on the various studies noted on Slide 56 and so we feel like we're poised to continue progressing our well stimulation activities under those new regulations.

We're already doing jobs in the field even though as Todd mentioned, our focus will probably be over the coming years on expanding out steam floods and our water flood operations where we -- that don't require well stimulation but I wanted to make the point that we're out there doing well stimulation jobs now and when they need our VCI threshold.

The other point I wanted to make is that Kern County, has recently completed a thorough environmental impact report and we expect that will also facilitate permitting in our key San Joaquin base and operations.

2013, in the legislature was the year of hydraulic fracturing regulation. In 2014, the legislature addressed water use in oil and gas operations. This year, the state has enacted energy legislation pursuing the Governor's goals of essentially doubling the use of renewable in electricity generation and energy and efficiency in buildings by 2030.

There were efforts to impose other restrictions on the oil and gas industry. Those were defeated in the State Assembly, most notable restriction on petroleum use in motor vehicle fuels and the potential expansion of the California greenhouse gas cap and trade program. And basically, we engaged proactively with the state to address and with the legislature to make sure people understand what we're doing in our business and the critical nature of it to the state and we've been successful in doing that.

And in summary, I would just like to note that we see state agencies progressing to a more predictable regulatory system and given the extensive portfolio of opportunities, we have in multiple drive mechanisms that you'll see over the next two days. We're very pleased to be able to prove to the state our commitment through our operational excellence, our thorough planning, and our sustained diverse coalition building that we are there to help the state meet successfully, its energy needs in a responsible manner.

And I'm happy to take any questions and then I will turn it over to Jerry Foster who's our manager of improved and enhanced oil recovery to talk about water flooding.

Any questions? Yes.

QUESTIONS AND ANSWERS

Unidentified Audience Member

Are there any early indications of additional cost from last Thursday's release for renewable plan and the DOC's new Director, his plans to overhaul DOGGR?

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

It's hard to say exactly how they want to interpret the new renewable plan. But one of the things that I think is very constructive about it is that DOGGR is staffing up to do more of the things legislature has asked us to do and ask the industry to do and ask DOGGR to do. And so, I think we welcome that kind of a review and that kind of outreach with DOGGR.

And basically, the things we stressed with the agencies is let's make sure that these reviews are handled efficiently, that they don't get in the way of recycling and reclamation of water and that they allow for projects to continue so that essentially, investments can continue in a regular manner while they undergo their review process.

Unidentified Audience Member

Thank you.

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Any other questions? In the back.

Unidentified Audience Member

To my understanding, the most of the taxes you pay for production are ad valorem taxes. Can you walk through how that works when most of your assets that's less of values would have been redetermined and then if you can help us quantify what the production tax savings will be from the lower asset values?

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Yes. And I'm probably the wrong person to get you the particulars on taxes.

Unidentified Company Representative

(Inaudible -- microphone inaccessible). And what it works is county by county, just like any other property taxes and that county tax -- excuse me -- regulatory regime assess you based on your reserves each year.

And in fact, the way it works is then you assess yourself how much that's going to be each year. And then, if you have an issue with your valuation, you appeal it, then there'll be arbitration later and there's a settlement.

But typically, it's fiscal years of the government so you should see later this year, early next year those taxes should come down in the counties we operate in. And then, if they don't, overtime, we've had issues in certain counties with certain tax assessors who have -- in particular, L.A. County, historically. But those have gotten a lot better and we haven't had to go arbitration every year but that's how it works.

So, it will come down. We don't know how much because it's a function of where they assesses at and then we have an appeal process if we're not happy with it.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

(Inaudible -- microphone inaccessible). The calendar year runs from July 1st to June 30th. And, you know, each quarter, we have as far as our other taxes. It's built in there and we'll guide going forward but you'll start to see the effect with lower prices in the second half of this year going into next year.

Unidentified Audience Member

Charlie, just a quick question on water, it's probably a small number, but I'm just curious if you've got any plans to start making the water distribution system, I guess, a revenue center as opposed to a cost center? Thanks.

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Yes. Right now, our plans have been to essentially use it to defray some of the cost of handling. But with our new agreement with the water district, we will be receiving money back for that. That will pay for, essentially, a lot of the improvements and over the long term, I do think we'll see an ability as we expand our water treatment to be able to basically get paid for that -- the barrels of water we're providing.

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Pardon me?

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Well, this point, it's still a little bit fluid, so to speak. But we feel like our newest agreement will pay back all the cost of what we're putting in to the system. So, that -- to us, that's very positive. And then as we -- as I said, we're looking at a number of other water districts and options too.

So, I'll turn it over to Jerry Foster.

PRESENTATION

Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

Good morning. Thank you, Charlie.

As Charlie said, my name is Jerry Foster. I'm the Reservoir Engineering Manager for the improved and enhanced oil recovery team for CRC. I began in the industry in 1976 working on the Trans-Alaska Oil Pipeline. Following college graduation with degrees in Petroleum and Geological Engineering, I joined Arco.

I did my junior engineering training in the Permian Basin, very quickly returned to Alaska to work on the super giants there. Following Arco's sale, we packed up the kids in July and moved to Saudi Arabia where I was the manager of the Qatif Waterflood Project. It was a field discovered in the 1940s and after two failed waterfloods attempts in the 1990s, we brought in online, on time, under budget, 450,000 barrels a day in 2003.

My wife informed me, since the project was finished and since the kids were approaching boarding school age, it was time to move and take advantage of the schooling system in Europe. So, I contacted Shell International, went to work for them, made my way up the technical ladder to their principal technical expert of waterflooding.

With Shell and then with Occidental, I was able to work on global waterflood projects in over 30 countries. So, if you haven't guessed it by now, we're talking about waterflooding this morning.

So, we have an option here. I can either compress 30 plus years of waterflooding under 30 minutes and talk really fast or we can use cliff notes. So, let's go with the latter.

So, we'll start with the definition of waterflooding and some of you are very quick on your smartphones and I see you've already looked it up so we'll see how close I come. I'll point out that oil fields have a life cycle. And so, we'll look at the recovery phases for those and put it in perspective.

You need to know why we waterflood. You need to know what our motivations are. The key one being increase in economic oil recovery over long periods of time. Going to details the key success factors for waterfloods are well known. We have no disadvantage over any of the large companies when it comes to managing our waterfloods.

But that's just talk. So, what I'd like to do is I'd like to show you our modus operandi at CRC and how we manage waterflood successfully. Our portfolio lends itself to very good waterflood management. And finally, I want you to leave with some takeaway messages.

So, here's the definition on injecting water to get incremental oil recovery and oil-bearing reservoirs and the two main techniques we use is to maintain reservoir pressures and to displace oil.

This comes from the society of petroleum engineers. It helps explain the different phases of oil recoveries lifecycle. Now, this has historical precedent and we don't have to follow this. But let me walk you through it quickly and then I'll talk about some exceptions.

We start with primary recovery. We drill well, we deplete the reservoir. If it flows naturally, great, if not, we had artificial lift to get additional oil recovery.

In the second phase, we can inject water, we can inject gas, but we add energy into the system. In the third phase, we have both thermal and nonthermal methods to approve recovery over and above that.

We don't have to follow these phases. The reason these exists is many of the projects had started primarily in the Permian Basin, depleted their reservoirs, the Texas Railroad Commission stepped in and said we're resource holder, we want more of the oil out of the ground, so they force unitize the disparate owners and forced them to waterflood. And from that, came many of the technologies.

Two notable exceptions. Again, we're not hamstrung by primary, secondary and tertiary. The Bonga Field offshore Africa, Nigeria delta, one of the biggest FPSOs in the world, floating production storage and offloading, waterflood started day number one, 300,000 barrels of water injection, 220 barrels of oil production. In Alaska, the Alpine Field, day one, waterflood. Nine months later, miscible gas injection.

Let's take a deeper dive into these oil phases lifecycle. On the primary phase, we'll drill our wells, we'll start depleting the reservoir. And on this graph, we have oil rate and pressure versus time. Obviously, the pressure is going down. Oil rate will come peak and drop down. Again, conventional water -- conventional reservoirs.

We come along with our waterflood, we begin injection. Oil rate comes up, peaks up, and starts to decline. Reservoir pressure comes up, very important. And on the third phase, for nonthermal methods, oil rate up, peaks up and comes down.

Now, according to the department of energy, the average recovery factors is a percent of original oil and place you should expect from these different processes is as follows, 10% on primary, anywhere from 20% to 40% on waterflood. And for the nonthermal treasury phase, some of these projects are still going on, frankly. We're looking to 10% or more.

Okay. Now, let's focus in a little bit more on that waterflood curve. One point I failed to make -- thanks to my annotations -- the decline rates that you'll see from our waterfloods are about a third of what you'll see in the unconventional. So, if you go in the Permian Basin, you're going to look at average annual decline rates for oil in the 20s. If you look in the Bakken, you're in the 30s and if you look into Eagle Ford, you're in the 50% annual average decline.

Here's the plot of oil rate versus time. We're under primary production and I began my waterflood. The first phase is called fill up. As I add water, the pressure goes up. The gas-oil ratio that I measured at the surface starts to decline.

This lasted very short period of time in the lifecycle of this reservoir and that's good because the reservoir engineers are really nervous. We spent the money for the pumps, facilities, maybe we've converted some wells or drills from the wells and we don't have any incremental oil recovery at this time, [against time].

The second phase, the phase we all love is in increasing inclining oil production. So, this is where we start paying the investment. But eventually, the water breaks through and it breaks through in a big way and we reach the third phase and this is the largest part of lifecycle and that's declining production.

Now, what you see here is the total fluid rate of oil and water comes up and it usually flattens out somewhat because of the facility limit. Perhaps the most important bullet on here is the last one, the sub bullet. Unless you're a geoscientist or an engineer, one and a half to three core volumes may not say much to you. But what it means is it takes us decades to process these reservoirs. They stay on for a long time.

Excuse the vertical scale, I've never worked a reservoir this shallow. We kind of need -- I think I'd mine it instead.

In this cartoon depiction, we have fluid saturation summing to a 100%. In Step number one, this is the last phase of primary. We have a significant gas saturation, we have an oil saturation and a connate or interstitial water saturation.

As I start injection, I hopefully form an oil bank or a shock front. The other thing to note on this cartoon depiction is the oil -- I'm sorry -- the gas saturation near the injection well has gone down. The pressure's gone up, gas has been driven back in the crude oil and gas wants to evacuate from the system so it's going to be production well.

In step three, I formed this oil bank. I'm propagating it to the production well. I've raised the pressure of the system and the gas saturation of the production well has also collapsed. This is the inclining production period I mentioned before.

This is good. We're monitoring all the surface readings to understand that this process is working correctly down the hole. Eventually, the water breaks through and we're dealing with most of the lifecycle of this waterflood.

You need to understand our motivations for waterflooding. It's the most widely used fluid injection process in the world in the oil field. We have -- there are numerous successful operators like CRC in the world and none of the big boys have any competitive advantage over us except in the front tier areas - arctic, offshore, ultra deep water. We don't operate there. But when it comes to day-to-day waterfloods, we do as good as anyone.

It's a mature technology. So, this is the audience partition -- participation portion of my presentation. So, I'd like you to shout out a number when was the first reported waterflood in the literature? What year? Shout it out. I'm not going to embarrass you. I promise. Shout it out.

And if you fail to participate, I'm going to help you out a little bit more. The first -- the oil industry in the world is in Titusville, Pennsylvania. That's in what, 1859? So, it's going to be between 1859 and 2015. Come one. Your numbers, people. Give me a number.

Unidentified Audience Member

1912?

Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

1912. Earlier. Come one. Anybody?

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

1880? 1880, first reported waterflood in the literature. It's been around for a long time.

One of the great things about working for CRC as a waterflooder is I have the volume of water I need when I need them. We have a nice recycled close loop system and that's not always the case in other places.

Good waterflooding provides the foundation for enhanced oil recovery processes. And again, I'll talk about nonthermal methods. So, we can put solvents in like CO_2, hydrocarbon miscible. We can put in alcohol and surfactants, polymers. Again, it provides a foundation for all those other processes.

It's a proven method to increase economic oil recovery. So, let's look at some really data. Okay. I went on IHS database, There's almost 10,000 waterfloods in the worldwide oil field database. I sorted by basin, I sorted by formation, and I've sorted by operator in the United States.

The reason I did this is to take as many variables as possible. I want you to look at the dark blue on the bottom. This are estimated ultimate primary recoveries, each bar is a separate oil field. And if you start from the left and moved to the right, what you'll notice is a lot of these fields run very close to that 10% number given by the DOE.

Now, there are a few exceptions when the primary coverage is greater and that has to do it natural [offer] drive. Mother Nature gave us the offer, we didn't have to necessarily put it in. Okay? But we're running about 10% primary. Now, look at the lighter blue and what becomes very obvious is the incremental benefit from doing a waterflood.

In some cases, certainly, many of them are double but in some places, it's quadrupled the recovery efficiency of the regional oil in place. And that's our motivation.

What are the reasons for this increased recovery efficiency? Pressure maintenance is one. If I can maintain average reservoir pressure, I can drive the oil recover for longer periods of time at higher rates, again, for conventional reservoirs.

If the gas stays in the crude oil, the viscosity is loss. The resistance to flow is less which means more flow. Another very important point is the displacement of the oil. I want to displace this oil.

So, in this particular case, we have to bring in an engineering term and that's called wettability and that's the tendancy of the fluid to adhere to a solid surface in the presence of another fluid. Sounds pretty boring, right? So, let's do some graphics and see what it means.

This is an oil wet system. This oil drop has great affinity for that rock surface. This is a water wet system. That oil drop, same oil but it's a different surface.

So, it doesn't have a great affinity. The second one, the water wet system is most of the reservoirs we had in California. Okay? It's easier to displace. You'll see on subsequent slides.

Why do I show you the oil wet system because as we get in to tighter reservoirs and more unconventional reservoirs, it's my opinion we're going to see more oil-wet behavior. So, we're going to have to be ready for it.

Okay. Tomorrow's headline from this meeting is not CRC research center developed nanobot tractors, okay? The blue tractor is my way of showing you that I'm injecting water in this reservoir and I have water wet system, it's easier for me to flush out the oil in the pore space.

If I have an oil-wet system, again, tighter and tighter rocks, more unconventional reservoirs, it's going to be more difficult. But there are some things we can do.

If allow that water residence time against that reservoir rock or if we alter the chemistry slightly, that water will imbibe into the reservoir rock, got to love that, and we can displace the oil more easily.

Another tool in our toolbox is to understand the geometry of our reservoirs and inject water down deep where we can. Again, the key success factors for waterflood are well known. Here's the engineering handbook, petroleum engineering handbook from 1992.

There were several papers before this so this isn't anything bran new, they've been around for long time. Let's go through them briefly. I need to know the geometry of my reservoirs.

The rock properties and types, permeability, the capacity to transmit fluids and porosity and storativity are very important. Continuity of rock properties. I have to have continuity between producers and reject -- and injectors or else I don't have a flood. So, that's what this cartoon to the right shows. It's an idealized reservoir with four equal layer -- equal layers, equal thickness layers and this one has a higher permeability so the water's going up quickly.

I never worked a reservoir that easy, just to let you know. If that looks complex to you, then we've got a long way to go. Fluid saturations are very important in their distribution.

The fluid properties are critical. The oil viscosity is critical. If the oil becomes too viscous, then I'm heading it over to the thermal recovery team.

Relative permeability is an esoteric concept used by reservoir engineers to explain the interference effects and competitive effects between oil, gas, and water in the pore space. I didn't have the slide but I can explain to you why traffic slows down in the 405 using these concepts. It doesn't make it go any faster but maybe you'll feel better.

Primary drive mechanisms are critical, reservoirs all around the world, there are six primary drive mechanisms. There's fluid expansions, solution gas drive, gas cap expansion, gravity drainage, water drive and compaction drive.

If I can figure out which of those drive mechanisms are at place knowing almost nothing else, I can tell you if we have a good waterflood candidate. So, I spent a lot of time working on those drive mechanisms. And even if I have one of the not so obvious ones, there's usually a trick or two we can do to make the waterflood successful.

Geology has a first order effect on waterflood performance. So, as geoscientist, we look at current processes that exist today and we take those back in time and if we take those back in time and understand successfully, we can understand about the distribution of the rock properties.

So, in California, let me go through a few of these briefly. We can have desert systems, windblown sand, Aeolian systems. We can have fluvial or stream systems, meandering streams. Alluvial fans. So, if you left here right now and I see you don't want to leave right now but if you left here right now and drove two and half hours north, it hit Red Rock Canyon state park and some of the best examples in the world of alluvial fans.

We have near shore deltaic systems and in California, some of our best reservoirs are deep marine turbidites. This is a cartoon developed by some colleagues of mine in the Middle East that we took the most pervasive reservoir, the [Schriver] reservoir in the Middle East. It's a tight matrix fractured reservoir and we looked at the complex geology and the complex water movement mechanisms and we came up with over half dozen movement mechanisms.

Water can move from the bottom, from the side, it can be rate sensitive in cone, it can move up falls, it can move from other walls and go through deep zones, why is it important that we understand this? Because if we understand this, we can place our wells in the right well type and influence the performance of the flow.

So, one of the degrees of freedom, what we have when we're designing waterfloods are patterns and many times from the primary production period, we're given the water -- we're given the patterns. We take those patterns and we convert wells to get our flood stared.

Now, again, up here, you have three of the more common patterns, 5-spot, 7-spot, 9-spot. Their inverted patterns because the injectors are the in center, you'll hear more about patterns when we talk about thermal tomorrow. We're not constrained by patterns if we understand the geology, we can form to the geology. And so, from the surface, you may not see repeating patterns.

We can also inject water downdip, down structure. When we do that, and we do it at the proper rates both injection and production, we get a very nice stable waterfront movements, like filling up a bathtub.

So, the highest recovery efficiencies I've seen in the most heterogeneous reservoirs in the world have one thing in common. They have gravity stable displacement. They get approximately three quarters of the original oil out of the ground.

Key success factors. This document comes from, looks like 1998, start the waterflood early in the life. I mentioned the Bonga example. It's not the only one.

Understand the reservoir's geology. I mentioned how important it is. If you have discontinuities in your reservoir pay, you may need to drill additional wells to overcome those discontinuities.

The one goal about developing with a 5-spot or a line drive, again, to me, that's not important because if you're sophisticated in your reservoir characterization, you can drill any patter you want.

Keep the pay open in injectors and producers. Makes sense once those zones completely flood out. I'd also like to shut them off.

Keep the producing wells pumped off. Keep the flowing bottom hole pressures in your production wells as low as you can. I keep the reservoir pressure high. You keep the production wells low. We get a good pressure gradient and we maximize the throughput of the system.

Inject below the formation parting pressures. We're under regulatory restrictions on what pressures we can inject at.

Operate the waterflood from the injector side. Now, the producer side is the sexy side. That's where all the revenue comes from. But most of my time is spent on the injection side because if I put the water in the right place, it's more likely to show up in the right place.

Finally, conduct a surveillance plan. Not the NSA kind of surveillance plans but we have access to our wells and information from our wells 24/7 if need be.

Two of the more common surveillance techniques that we use at CRC are the bubble maps and reservoir simulation. In the bubble map depiction on the left, we have -- we have circles that depict a volume of water production in blue, oil production in green -- so, this circle here has oil production and water production -- and then the plum color is water injection.

And from the map, you can see that there's some areas in the reservoir that we haven't fully drained the oil yet. So, those are very prospective areas for us to go in and look at.

Also, to bring in the full physics, to bring in the deep, you see the equation, to bring in the mass balance, the material balance and the equations of state, we use finite difference reservoir simulation and what that does, this is an actual example from the western shallow oil zone waterflood, we took core data and we developed the reservoir description down to one foot, in some cases six inches.

We put those rock properties in a model and we put it on our reservoir simulation. That allowed us to predict how the waterflood will perform. Again, this is all before the waterflood has occurred.

And in this case, you can see by observation the waters moving out very quickly in the upper part of that reservoir and not so quickly in the lower part. So, now we have a decision to make how can we increase the injectivity of that lower part of the reservoir or pinch back some of that water injection so we get even sweep. Again, this is done ahead of time so we can send that information to the operations people and they could come up with the appropriate equipment and completion design.

Proper integration is key. Let's follow some water around the system. Got my barrel of water and I treated it.

Now, I'm going to inject it. I inject it. I monitor the rates, the pressures. I calculate injectivity indexes, I look at diagnostic plus. I look at the vertical profile.

That water goes out into the reservoir as it goes out of the reservoir, I can infer what the reservoir description looks like. I can improve my reservoir model.

In terms of surveillance, I use diagnostic plots, pressure transient analysis which allows me to calculate reservoir properties. If my reservoir is disconnected, I can drill and fill wells.

I do electrical logging or I put electrical tools down the hole and look at the response curves. And I do repeat formation test of pressure so I can see the pressures vertically in this well. This has happened continuously.

As that water moves to the system and hopefully increases the pressure and displaces oil, I can go ahead and do similar things with the production side, the productivity index, the profile.

Look at the lift methods, watch the water chemistry. I don't want too much scale on the system. As that water and oil are produced, they're separated, and the cycle goes again. Okay? So, we want this to be very efficient because we're going to do it many times.

So far, it's been talk. Lots of theory. Let's look at CRC's modus operandi. We buy fields from other operators that they've gotten tired with, they're bored or don't fit their portfolio.

In the case of Mount Poso, we bought it in 2007, we studied it. We determined it was a waterflood candidate, we put it on waterflood and now we have tripled the oil production. Again, that's our MO.

I want you to look at our portfolio in larger sense.

We have currently, 94 fields on primary production. We are continuously screening those fields for technical and economic indicators that they can move into another category like waterflood. We have 17 fields in waterflood with a significant reserves impact.

Those fields are being screened whether they can go into the enhanced oil recovery category. Now, to the right, I've got the bar charts you've seen before and it shows steam projects. I'm not going to talk about steam. I'm purposely not talking about steam because we're going to be talking about it tomorrow.

But our recovery efficiency as Todd mentioned before, we have about 15% on our primary and we're driving towards 20. On our waterfloods, we're at about 25. We're driving towards 40 or more. So, good growth potential.

So, these are the takeaway messages. Waterflood keeps those oil rates higher for longer and I don't mean for a few years, I'm talking for decades, okay?

By doing so, we protect our base production. It's a mature technology, the critical success factors are well known. The first waterflood in California was in 1953 in the terminal, in the L.A. basin. The second waterflood in California was in 1954, in the Calitroleum pool in the San Joaquin basin. We've been doing this for a long time.

Maintaining reservoir pressure keeps the viscosity down of the crude oil. It's easier to flow. It also maintains rock properties. So, permeability and porosity are maintained with this pressure. We can mitigate and sometimes eliminate subsidence.

It provides the foundation for numerous EOR processes and you saw our portfolio. I mean, there was so many in primary and a number in waterflood. We're teeing these projects up for the next phase. Again, we get the right technical signals and price signals, these things will move.

And finally, CRC has demonstrated success in waterfloods. What I want to do now is I'm going to turn it over to my former reservoir engineering manager, Frank Komin, and he's going to talk about the Wilmington field among other things and what you need to know about Wilmington is Wilmington is known worldwide as the best in class high water cut field with the longest life.

So, again, waterflooders in the world, we always refer to Wilmington. So, you'll hear more about it now. I don't know what happened to my question guide but I think if there are time for question, Scott?

QUESTIONS AND ANSWERS

Unidentified Audience Member

You mentioned the range of increasing recovery rate from the waterflood is 20% to 40%. You showed a slide that had that in there for a bunch of -- for a bunch of projects.

Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

Yes.

Unidentified Audience Member

Is there any newer technologies that has the potential to reduce that range or to push that range to the upper end and where you could have greater confidence -- it could be at the upper end or a nearer range.

Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

I don't know of any new technologies per se. I think a lot of it is the reservoir that were given. And I mentioned the reservoirs that performed the best on waterfloods are ones that are gravity stable. Ones that have a significant dip angle to them.

Believe it or not, reservoir quality is not the determining factor. We have some fairly tight reservoirs in the world where we get exceptional recoveries. And again, it has to do with gravity as given to you, right, it's how you make best use of it.

Now, there are some technologies being tried by other companies, they call boutique blend water injection. So, what they do is they alter the chemistry of water and the water absorbs on to the rock and oil desorbs from the rock. The last -- the last time I'd seen that tried, it wasn't successful. It's being done in the lab but I don't know anyone that's done it commercially. There is something called LoSal that BP has patented but I don't know if that's a tax flood or not because LoSal, if it's shown to be an EOR benefit, then you get some tax benefits.

So, again, looks good in the lab but you have to take it out in the field and do something with it.

You don't want to hear about the 405? They already heard about it. The guys here heard about it. They're tired of hearing about the 405 and relative permeability. They don't want to hear about it anymore. I understand.

Unidentified Audience Member

Jerry, the -- one of the criticisms that's been leveled at CRC is that as the waterflood become a bigger part of your portfolio, water handling in terms of accountable cost and operating cost is going to become an issue. Can you tell us how CRC handles that issue? What the current water cut on those fields is and what point do you cut off the economic life to replace for --

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Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

Right. And that's a common problem all around the -- let me give you some numbers and then I'm going to defer a part of that question to Frank because he's got the -- he's got the numbers you want.

In most of the offshore fields I worked, 10% water-oil ratio is your economic cutoff. In the best managed waterfloods I've worked on onshore, the water-oil ratio is 30. Okay, 10 offshore, 30 onshore. Again, very well managed fields.

And what Frank's going to -- it may not be a part of Frank's presentation but in Wilmington, they operate significantly higher oil ratios. The problem with that kind of thinking is you can't extrapolate it. Because what happens in reality is those water -- those wells hit their economic limits, we review them. The operational people go in and look at them, Bob Barnes and Frank Komin, they look at it, they figure out ways to shut off that water if it's unnecessary.

If we can't shut it off, then we'll shut it in. But that frees up facilities capacity for the next well. So, again, I think it's a legitimate criticism that if you were swamped by water and you had no other place to take it and you weren't thinking and progressing, you would eventually go out of business. But we're very low bureaucratic, nimble operator and so I don't see that as a problem with CRC.

Unidentified Audience Member

[How tight are the] rocks in terms of the permeability that you --

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Jerry Foster - *California Resources Corporation - Reservoir Engineering Manager - IOR/EOR Team*

Yes. So the question is how tight are the rocks. A number of our waterflood reservoirs are conventional. They're going to be 25 to 30 millidarcies or greater. We have some that are Darcy rocks.

What I was talking about earlier about the -- our future's going to be in some of these tighter reservoirs, we have some reservoirs that are less than 1 millidarcy. Those reservoirs are commercially waterflooded in parts of the Middle East. Some of the fractured carbonates are down to 1 millidarcy and they've, over the year, through painful processes figured out the well types and the stimulation procedures that they need to make those waterfloods work.

So, think of our portfolio, we're getting int o the tighter and tighter rocks with time. We just have to. And we will be in unconventional. We look at providing pressure support. Nothing to announce. I'm a conservative engineer, so until I can demonstrate it, I'm not going to announce it.

Okay? So, all yours, Frank.

PRESENTATION

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Thank you. This is -- okay.

All right. Well, good morning everybody and it's a -- it's a pleasure to be here. I'm going to, actually, be with everybody for probably the next couple of hours. We're going to go ahead and review the Southern operations and give everybody an opportunity for questions and then I'm going to spend some time trying to prepare everybody for the tour that we're about to go on and we'll probably be living there in -- within the hour, hour and half and we have several tour guides in the back that I'd also like to introduce.

But first of all, my name is Frank Komin. And I'm going to tell you a little bit about my background. I've been 37 years in the industry, the first 22 years of that I spent with Arco and then in the 15 -- last 15 years with OXY and now CRC.

I've experienced mainly around the domestic U.S. and Alaska and I've spent the last 18 years here in the L.A. basin. So, today, I'm going to talk about kind of the agile adage that world class reservoirs just tend to get bigger and better as time goes on and you've heard that thing many times today. And I think that we will provide some examples of why we believe that to be true.

And the fields that I speak about that they are characterized as being a very sensitive environments as being in urban settings and coastal settings in agricultural settings and these fields are all generally well established with very low technical risk and very repeatable technology.

So, we're going to go ahead and start and we're going to take a look at CRC's four major producing basins. And the slide shown in the upper right, we're going to start today on the south with the L.A.basin and the Ventura basin and then conclude tomorrow in Bakersfield with the San Joaquin and the Sacramento basins to the north.

The two southern basins that I'll talk about are just absolutely very, very rich hydrocarbon basins. CRC's fields on these two slides on the bottom are shown in blue.

Consist of over 30 producing fields with greater than 14 billion barrels of original oil in place, these two basins produce a combined 42 barrels of oil per day and are extremely oily as you've heard before and approximately 96% of the reserves that we have in the Ventura basin are, in fact, oil.

So, Jerry who just -- Jerry just concluded it with a discussion of waterfloods and most of the production in the south, in fact, does come from waterfloods. This shows steady production growth during the past five years from our active waterfloods and that steady growth is coming from a culmination of things maintaining and something that we're doing very, very rigorously. Todd referred to it and that is managing to our -- to base -- to low base declines. And to supplement that, we have a very active drilling program including uplift from other PSEs and I'm going to discuss PSEs in just a bit.

So, the L.A. basin is one of the most hydrocarbon-rich basins, really, anywhere in the world if you look at it on a per square mile basis. It's relatively underexplored. Most of the majors departed this area back in the 1970s and 1980s. It's very, very consistent with CRC's strategy of acquiring world-class reservoirs and then redeveloping those reservoirs through the use of technology and through the use of our expertise and capital investment.

And on this map, it might be a little harder to see but our two largest examples in the Los Angeles basin utilize in this approach are the Wilmington Field and the Huntington Beach field. And I'll talk just briefly about Huntington Beach. It's shown to the southeast of Wilmington in the yellow.

We acquired the field back in 2011. And we've had two drilling rig program going there but to really only drill for about a year and a quarter and during that time, we've added over 2,500 barrels of oil per day. That happens to represent the first drilling that's taken place in 25 years in that field.

Consistent with the price down term, we have curtailed our drilling and we're taking a drilling time out right now but we're continuing with an active base decline, base management decline while at the same time we're building up our queue of candidates.

So, I'll talk -- I'm going to talk a little bit more about the Wilmington field. That certainly is one of our bigger fields. It is, in fact, CRC's coastal flagship asset. The regional map on the upper right talks about the fields.

It shows geologically that they form along that -- that Newport-Inglewood Fault on a northwest trending fault system. And the thing, obviously, that makes it very, very unique and I think those who were at dinner last night saw that first hand is that it underlies in a very, very active port and a bustling city.

Wilmington is not only the largest field in the Los Angeles basin but it's among the top five largest in all of North America with well over two and a half billion barrels having been produced to date and we believe much more to go.

It's recognized not just for its unique surface facilities which we're going to see very quickly on the tour but it is also recognized, as Jerry alluded to, in the subsurface for its world-class waterflood management techniques.

The fields been showcased on an average over 100 tours annually. We have hosted numerous experts from around the world including countries like South America, the Middle East, and all throughout Asia.

On the lower right, you can see Wilmington's geologic structure. It's really a classic anticline but it's extremely faulted up with multiple pays that give us up whole opportunities as well as deepening opportunities.

And on the lower right there, you can see the banners on that map highlight the progression of acquisitions we've made in the field during the past 14 years. It's really a highly -- highly mature waterflood. There was a question about it so water cut.

We produced about a million and a half barrels of water per day and basically a close system. And of that, in that puts us at about a 97% water cut which would make you think that we're probably going to be shutting this thing down and it's reaching its economic limit very quickly.

But in fact, it has an extremely long remaining life. At the end of 2014, our SCC reserves had us going in nearly 50 years of remaining life and then some. And we're just consistently finding new opportunities. I'm going to talk about that in just a little bit more.

In particular, as you focus on the lower left, it shows a history of strong reserve replacement in the field both proved and producing reserves. They've more than doubled since the initial acquisition back in 2000. And that's largely the result of purchases that we made and redevelopment expertise.

So, Wilmington has -- it's really helped provide CRC with our license to operate in coastal California. We built a very, very strong reputation over the years. As an operator of choice and we built a strong reputation with the -- the city of Long Beach and with the State of California during that time.

Moving on a little bit and talking some more about how big fields get bigger. As Jerry described in his waterflood process, Wilmington is a mature waterflood with production coming primarily from long-term recovery. It's also supplemented by an ongoing drilling program which has occurred over the years. It's really a prime example of world class size waterfloods that tend to get bigger with time and Todd mentioned as where more activity begets more inventory.

And if you look just on the lower left, it shows that since 2011, we drilled over 500 new wells in the field and, again, an example, our remaining inventory has actually grown, generally a thousand wells during that same period of time.

Okay. A little bit about geology. Like most of the Los Angeles basin, Wilmington is an offshore turbidite geologic system in which we have extremely good experience and regional understanding that we think we can apply to other fields in the area.

The reservoirs, like most in California, are just massive sequences of sands and shales with over -- well over a thousand feet in our case of hydrocarbon pay in the month is a moderate equivalent and it creates a huge number of recompletion opportunities for us.

Something that is a little unique technology for the Wilmington field and that is geosteering. And a lot of people look at this and they think it's sort of a cartoon depiction but it really isn't. It's an actual depiction of existing wellbore traces that exist in the Wilmington field. It's Wilmington as among, if not the leading field in the world in terms of the densest accumulation of wellbores and electric submersible pumps anywhere in the world.

In this field, a well placement is absolutely crucial to us to -- and it often obtains -- requires a very complex well designs in order to avoid colliding with the existing wellbores and enables us to reach precise bottom hole targets with bypass pay.

And this is a technology that we have used in other places in field like, it's a technology that we can use elsewhere in the L.A. basin as we continue to grow. It's one that is well suited to urban settings where directional drilling from small pads minimizes the surface footprint that's required.

Okay. I'm going to talk -- I mentioned the product sharing contract just a bit ago but I will go in to how that -- how that works for us. It's a very unique ownership arrangement that we have with the State of California and the City of Long Beach. It is very much like a production-sharing contract. It's common elsewhere in the world internationally. And there's several differences.

One difference that's better is that we have -- we're able to recover our costs in this field immediately. Most of the ownership comes from two large production-sharing contracts, the Long Beach unit and then the onshore Tidelands field.

And just quick -- you know, just quickly, the graph on the right shows basically how the process works. The blue area represents how the fields were expected to play out without any intervention and basically operating status quo through to depletion.

And the red area on top of that represents the optimized waterflood program agreement or what we call the OWPA. At the Long Beach unit, we reached OWPA agreement in 1992 with the State of California who opened -- who owns the minerals and as part of that agreement, the operator is required to provide the technical expertise, resources, and capital.

And then the operator would guarantee the state their base profits -- again in blue -- and then return split the profits incremental oil generated above the base in red and that split is 51% to the state, 49% to CRC.

And that agreement at the Long Beach unit on the upper right was so successful that we purchased the adjacent Tidelands property and negotiated a similar OWPA with both the state and the city which was executed in 2010. And since that time as you can see through our redevelopment program, incremental productions grown steadily by 4,000 barrels a day.

CRC does recover its cost -- excuse me -- recovers its profits and costs in the form of oil production so the production sharing contract is very sensitive to swings in oil price. So, for example, a swing in the oil price of a dollar at $50 price range that we're at right now results in a production impact of about 250 barrels of oil per day for the full year.

Then again, a couple of other futures that are unique to this PSC, unlike the international production sharing contracts, the key advantage of this PSC is that the contract is evergreen, runs through the end of the economic life of the field. And then finally, the bulk of the [dynamic] cost and we'll get a chance to go out and see -- see the islands and wells and the facilities, the bulk of the dynamic liability is to be borne by the state of California.

Okay. Let's switch to Ventura. The Ventura basin to the north, it is, again a very, very prolific hydrocarbon basin, a huge amount of opportunity and growth. And really, this is one that we're very, very excited about it and we think there's a lot of running room here.

COC operates 29 fields. Many of those are owned in fee. We have four active waterfloods that are in the early stages of development.

And some of these waterfloods are direct offsets to major fields like the world-class Ventura avenue field that's operated by Aera that has a recover -- waterflood recovery approaching 13% currently.

And conversely, many of CRCs fields are future waterflood targets with an original oil-in-place estimated at three and a half billion barrels but it has a relatively low recovery efficiency of 14%.

And at the end of 2014, you know, following the price downturn, we -- we redirected our technical staff to build out our portfolio with individual field life plans, and we did that so that we'll be poised to respond when prices do rebound.

And some of the work that I think is interesting, recent work performed by some of those field life planning teams is showing that our original low oil-in-place estimate probably have been understated maybe more than 50% higher than previously thought.

Finally, to conclude this slide, the section to the bottom right reinforces the basins upside potential. We have well over 2,000 remaining locations in Ventura basin and a significant running room for future reserve additions.

So, this is a first in a series of slides that I'm going to show about our operational results for the first half of this year and it reflects performance since we last met late in 2014 on Halloween.

So, we currently operate a single drilling rig and seven production rigs. Production is ahead of plan on both the gross and a net basis. In fact, it's hard to see that's the graph at the bottom or the numbers at the bottom. But we're meeting or beating our projected 21 performance for all areas of our operation that we control with the exception of course of price.

This slide just shows a standard score card that we use to describe the results of our one rig Wilmington base drilling performance through the second quarter. If you look at this graph, the cross hairs on this graph represent the point at which both our IP, our initial production rate, and our drilling cost meet our AFE projection. And to have -- to meet AFE projections yields returns that are well in excess of our 1.3 VCI hurdle.

So, if you look at it, the upper right quadrant, of course, is where you want to be. And it shows that our actual results have outperformed our targets. So, through Q2, we are 18% under our AFE cost and we're 9% above our initial production target. And incidentally, our initial production target represents the average of the first 90 days of production for each individual producing well.

Okay. This shows production. We measure our production a couple of different ways. First of all, by both the net and gross production and the gross bars are represented in -- the gross is represented by the bars. The net production is represented by the green lines.

And the reason that we do this is because the gross production look enables us to back out the PSC-driven impact on our production rate. As you can see, we're both well ahead of both gross and net and that's largely the result of, again, an active base management program combined with -- with an aggressive 2014 yearend drilling program.

Okay. So, we'll look just a little bit at cost. We'll talk -- start with operating costs. You can see they're down considerably year-over-year from the first half of 2014 at $30 per barrel and the first half of 2014 at $22 per barrel.

In fact, if you look specifically at just the Wilmington field which comprises a big part of that and I mentioned it was producing at a 97% water cut we are managing to operate at just under $18 per cash cost on a gross barrel basis.

And all these savings that you see up here really are the results of -- of a number of things. There's really no one silver bullet. They range from reductions in contract workforce from improvements in well service, from improvements in well failure rates, energy costs and many ideas that have originated from within the workforce itself.

We believe we have a workforce here and a culture that is one of continuous improvement that's one where our employees recognize the importance of maintaining our costs down and we continue to see additional efficiencies that come through the organization.

So, the other cost category, we'll look at capital spending. It's down significant from our levels in 2014, our reduction of 80%. I think it was mentioned previous -- previously, a big, big part of that is what we curtailed very rapidly. Our -- our drilling rigs fleet down from seven or eight at one time to just almost instantaneously down to one drilling rig which is where it is currently.

But the savings don't just represent curtailments and drilling rigs but also represents some very good work that's been done in the area of capital efficiency. And that capital efficiency on the drilling side was realized from a culmination of things from service rate concessions to repeated efficiencies and work planning and reductions in nonproductive time.

These efficiencies are going to enable us the ability to drill additional wells this year. We believe somewhere from five to eight additional additional wells will be drilled in 2015 beyond what was planned and at the same overall cost of what was previously planned.

Okay. I'm going to close with this slide. And, you know, to summarize, in the south, we have world-class sized assets with a huge amount of opportunity and future profitable development growth. Specifically in Wilmington, our largest field, you see example record of success. We've achieved operating in a very, very sensitive urband environment in California and we believe we have a number of redevelopment opportunities that can be applied elsewhere within the south, and in particular, Ventura basin which I mentioned previously.

And that concludes my remarks and I would be happy to -- to take questions.

QUESTIONS AND ANSWERS

Unidentified Audience Member

Thank you. Thanks. To be clear, on a one-rig program with the -- I think you said seven or eight rigs in the field altogether, one drilling rig, what do you -- what's the prognosis for the medium term production profile in this environment. Can you hold it flat?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Right now, our production profile is that we have at roughly an 8% decline. Some of that is coming off of late 2014 where we have a little bit of a production ramp and we're starting to see that stabilize. If you look historically at sort of mature waterflood wells, it typically declined on the range of 5% to 6% together.

Unidentified Audience Member

So, that's on the growth basis, right? The 8% decline.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

That's on a gross basis. Yes.

Unidentified Audience Member

Okay. So, what would it -- obviously, you're net is getting the offset from the PSC, is it fair to think -- I mean, how should we think about in the event of an oil price recovery [position], you lose the PSC volumes but would the activity level increase the offset up? I'm just trying to understand what happens through net production. Thanks.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes. The net production would continue -- would go down as a result of that. That's true. We would have to look individually at the well economics that we have. As an example, when we had $100 oil prices for that same period of time where we're drilling at -- in the Wilmington field at a pace of three drilling rigs and that was well in excess of our 1.3 VCI.

We have partners on the field that don't see that same PSC effect and so we run economics both ways. We run it on a gross basis and on a net basis that it needs to exceed both terms.

Unidentified Audience Member

Just so I understand how the PSC contracts work, on the slide that shows the OpEx coming down from $30 a barrel to about $22, how much of that is from the kind of cost structure actions you talked about versus the nature of the PSC contracts and lower price oil world this year. Are you just getting more barrels and CRC, you know, pays a 100% of that operating cost? And so, it's more function of number of barrels you're receiving?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

A part of it -- part of it is that what we've seen, actually, you divorce the PSC part of that and you just look at at gross for the first half of 2014, we were at roughly $30 a barrel and we've reduce that down to lower than $20 a barrel on a gross basis currently.

So, we seeing -- we're seeing the decline. You know, part -- part of what we're seeing again is that -- is some of the flash production that you see at the beginning of the year coming -- coming down.

Unidentified Audience Member

Same -- same topic.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes.

Unidentified Audience Member

Hi, Frank. Same topic, a little bit different angle. As you take a look at the cost productions that you've achieved, how much of those can you maintain in giving your long-term outlook of mid-60 oil price environment and what are you doing now to make sure that if group prices do jump up, you can actually achieve those cost savings, not have them runaway from you as they have in the past?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Well, you know, and maybe it's a cliche but we are continuing constantly to work on -- on cost reductions. You know, maybe the best way to describe that would be looking back in time.

If you look over the last three years, the improvements that we've made in operating costs and downtime and capital efficiency, you know, we've reduced the costs substantially down to the -- from the upper 20s down to today, I think, it's 1$18 or $19 a barrel and we're going to continue to do those things.

We have -- again, it's no one-thing. It's no one silver bullet. It's going to be a number of initiatives that we continue to drive. I think one of the areas that's kind of opportunity rich for us right now is to continue to be efficient in our -- in well maintenance.

I think we have some areas where we can be even more efficient than we are now and continue to drive those costs down but, you know, it is a mature operation. It's something that everybody recognizes that we're going to do everything we need -- that we need to do to continue to keep those costs where they -- where they are in check.

Unidentified Audience Member

Are there -- are there specific things that CRC is doing now that you can tell us about that OXY was not doing for these fields that have a direct impact on your cost structure that are well planning or renegotiating service contracts or, you know, what -- this is a finance graph -- there were like numbers?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Those were two of them.

Unidentified Audience Member

Okay.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Some of those are repeatable, some or not. I mean, some of the concessions that we see in service contracts concessions, you know, we're going to do everything we can to maintain those but see a lot of repeatable sustainable kind of cost improvements. Again, it's on -- it is on the well work side. I could show you come things both on kind of reductions in downtime that we've seen overtime through just good ideas and efficiencies.

Todd Stevens - *California Resources Corporation - President, CEO*

Other places, I think one thing to think about -- am I on -- is if you look at operating costs, you think about what's going to go up if when prices go up, energy cost could go up and maintenance work overate cost could go up because they're a function of the product price.

I think everything else is sustainable and I -- you should probably ask Bob the same question tomorrow but I think Frank would say the vast majority of the operating cost with the exception of those two categories which are arguably out of our control, activity driven and energy cost are sustainable. And I think on the capital side, if you think that a lot of it has changed from the standpoint of processes, I think a lot of it has to do with how transparent and focused we're trying to be. I think if you went and talk to the operators in the field here and elsewhere before, when we're OXY, they just thought they're part of a larger organization and we talked to those folks, you know, they don't think what they do really impacts anything.

Now, I think we're being very transparent. We're telling them about VCI. We're telling them how they can compete for capital. When I go out to morning meetings, the one question I get asked is how can I get capital for my asset? How are we going to compete again and what do we need to do and they know that what they do on their impacts on the field make the difference and they can compete themselves for capital.

We have a good example of that up in the north where some team actually got capital mid-year because they worked hard to achieve that but I think it's now the level of transparency for my standpoint both externally and internally, we feel like they are -- it gives people more purpose. They understand it's not a black box at a big corporation, they're very focused, they understand how everything works much better that way.

Unidentified Audience Member

Following up on that --

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes, sir.

Unidentified Audience Member

Following up on that, how much then the self help versus the cyclical decline which we're alluding to in lower energy prices and all that in terms of your OpEx?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I'm sorry --

Unidentified Audience Member

How much of your OpEx saving were self help?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Was what?

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Versus cyclical? I think the cyclical part would be the cost concessions that we're saying. But as Todd mentioned, I think a big part of that is -- are things that we feel like we can sustain in the future --

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Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Todd Stevens - *California Resources Corporation - President, CEO*

So we were at -- we were at 30 growths last year. We're in 18 in change growth this year. What's [John's] asking is approximately how much of that and I think we can feel comfortable saying, you know, so you say that's $12 what's around, so more than six of that is going to be sustainable in our mind over the long haul through the cycle.

Unidentified Audience Member

Okay. The next question for me was in terms of your spending, how much was on work over related activity for the first half of this year?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Of the spending how much was work over -- I'm looking in the back, Charlie, you wouldn't happen to know?

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

(Inaudible -- microphone inaccessible).

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

For the south?

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Capital work-overs is about 50. The capital ones are about 50 and then the expense work overs are reflected in operating cost. So, that's what you'll see there.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

For the whole -- whole company?

Charlie Weiss - *California Resources Corporation - EVP - Public Affairs*

Yes. That's both north and south, not just --

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes, sir.

Unidentified Audience Member

A couple of years ago, the industry -- including OXY, was flirting with the idea of Monterey shale, horizontals and the Ventura basin. I'm just wondering, is that concept dead or is it on hold or how should we think about that?

Todd Stevens - *California Resources Corporation - President, CEO*

Let me answer that, Frank, and I think I'll talk about it then I'll let Darren say something who's sitting right next to you. I think -- if you think about it, people are really talking about the lower Monterey. Particularly, you have these studies out there and the funny part we're actually around 50,000 a day from the Monterey, from the upper Monterey currently.

So, the fact this report came out and said there's 21 million barrel of recoverable oil, I guess, in a year and a half, we can, you know, have all the recoverable production in the Monterey at that point.

But the lower Monterey really hasn't been tested. I mean, you could, you know, on my hands and toes and your hands and toes, we can count the number of wells that have been drilled and completed in the lower Monterey. So, I think it's one of those things that people have been too excited about and also they've been, you know, too detrimental about it also. I think it's really misunderstood and it's something that we will actively want to work on.

We've spent some, I'll say, R&D time in dollars on a minor amount currently but the reality is it's something that's out there from a resource standpoint. It's enormous, it's ubiquitous around California. Like Frank said, there's Monterey down here, they just call it a different name.

And, I mean, Darren, you've looked at these things. What do you want to opine on that? You could ask him more about this tomorrow. He can talk about it.

Darren williams - *California Resources Corporation - EVP - Exploration*

Yes. Obviously, tomorrow morning, we're going to talk about the exploration program and a portion of that will be dedicated to the shale potential in California. What I would say is that we see significant resource potential in the assets that we have. We're being pretty deliberate in how we build our understanding and how we want to go about prosecuting those various reservoirs and ranking the different opportunities we have.

So, what you'll see tomorrow is not so much the Monterey but another stereographic level called the Kreyenhagen which we've made a lot of progress in. We've established vertical production in and kind of can define that place as a good example of what you may be able to expect from a California shale play.

So, everything we see points towards reservoir properties and reservoir extent that would give you a successful shale play and we'll go through that in detail tomorrow.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes. Two questions over here.

Unidentified Audience Member

Thanks. The $58 million capital investment spent year-to-date, does that -- is that just drilling in completion or does that include facilities infrastructure or everything else? And then secondly, is there a good way to translate that into a dollar per barrel F&D cost?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I think that includes -- that includes both facilities and the drilling piece year-to-date. I don't have a number offhand where you can get that -- we can get back to you with that -- the number offhand on the F&D cost.

Unidentified Audience Member

Maybe to slightly rephrase the question about shale, have you hired any geologist or engineers that have worked for companies that have been successfully drilling horizontal shale wells being it's a slightly different skill set?

Todd Stevens - *California Resources Corporation - President, CEO*

Well, I'll opine on -- I hired Darren. And for those who don't know Darren, actually, he's a production geologist working in Oklahoma and developed and started implementing their Woodford shale at Marathon and very familiar with other plays around the world including offshore west Africa. So, I'll let him -- talk about -- the talent we have and who we've hired at the company.

Darren williams - *California Resources Corporation - EVP - Exploration*

Yes. To follow up on Todd's response there, I'm kind of one of the new members of the leadership team and I've been on board about 12 months but as Todd said, one of my most recent pertinent career moves was I spent three years in Oklahoma City from 2010 onwards where I pretty much established Marathon's Woodford shale and conventional development team and kind of run that for three years.

And, you know, during that time, we also basically established what is their ongoing Oklahoma resource basin growth strategy with their SCOOP and Stack plays. So, personally, I've spent three years running multiple rigs in shale plays and doing that kind of activity.

I think when you look around the company and we've, you know, gone through and that's one of the first questions I ask in terms of what are the resources we have available and that kind of thing and you got to remember, when you relate back to CRC's parent company in OXY, we had a Permian position, they had a Bakken position. So, you can put in to perspective, we have employees around the company who've been involved in these different plays relative to OXY's activities in the past as well as some other hires who's come in from other plays around the U.S.

So, the quick answer is yes. We have the employees and I'm a good example of some of those hires that have come in relative to that.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Question in the back.

Unidentified Audience Member

Do you have a breakeven -- breakevens in OpEx plus CapEx per BOE for the Wilmington field?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I am sorry -- I couldn't -- I couldn't hear that.

Unidentified Audience Member

The breakeven per BOE.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Right now, in Wilmington, it's -- if you added fully loaded cost and included just not just cap -- CapEx or cash cost, what I've mentioned previously but included taxes and DD&A, it's approaching $30 or low 30s.

Question in the front.

Unidentified Audience Member

Going back to the PSC for a second because, obviously, you're getting the -- you get the recovery when the oil price goes down the state, you know, it's obviously getting the ops side of that. In the event, we had a [lower longer] oil price, what is the likelihood that the state changes the PSC to incentivize continued new capital going to work?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

There's no -- the PSC wouldn't be changed at all through the -- through the life of the field until the economic abandonment.

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

The production-share contract? No, that's been fixed since the time of -- since 1992 in the case of the Long Beach -- I'm sorry?

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Todd Stevens - *California Resources Corporation - President, CEO*

(Inaudible -- microphone inaccessible). Go walk them through again back to the original -- the different contracts because the one was established in 1992. You know, when we bought Tideslands, we created a new one that was the same as that also.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes, that was -- that was -- that was basically it. There's -- so, there's essentially three separate production-sharing contracts in the field. One is the one that was established back in 1992 which is the one in the upper right, that's the long beach unit. Production sharing contract.

The one on the lower right, those are the -- there was actually -- that actually represents two production sharing contracts, kind of splitting the west Wilmington field into two pieces. One of those, primarily with the State of California went primarily with the city.

In the terms of those -- of that PSC is very similar to the terms of the PSC that we negotiate in Long Beach unit.

Unidentified Audience Member

(Inaudible -- microphone inaccessible).

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

That's right. Yes. That is right. So, there's three pscs. The first one was 1992 upper right; lower right is roughly 2010 when those were initiated.

Todd Stevens - *California Resources Corporation - President, CEO*

All the contracts originally were cost plus 4%. I mean, so that was until 1992 or until 2011, they were all cost plus contracts until we renegotiated and incentive this production essentially.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

Yes, sir?

Unidentified Audience Member

So, in this environment, you guys are obviously high grading a lot of your portfolio, how do you think about workovers and the amount of candidates you have going forward from today based off on where the strip is? And how long can you keep going like this?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

As we -- as we look at economics, how do we determine the economics and how competitive those are?

Unidentified Audience Member

More so from how many candidates do you have today? I mean, like, everyone's going towards workovers right now because of the capital intensity is just nearly as big as, you know, drilling a new candidate, right? So, when you think about your inventory today, how long can you keep going at this -- at this rate?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I think we can -- we can keep going for a while longer. Again, as Todd mentioned, we're going to live within our cash flow means. And so, we have a long portfolio of opportunities and it's a just a matter of how you allocate the available capital for those.

Workovers are definitely our most economic opportunities that we have. We've done something in the order of 35 so far in the south and we have at least equally that amount that we could go after, again, if the proceeds became available to us.

Unidentified Audience Member

So, you think in, like, maybe a couple of years of this -- at this kind of rate?

Todd Stevens - *California Resources Corporation - President, CEO*

No, it is much longer. But I think the issue really is the PSC is -- it tempers the downside. It tempers the upside. It moderates things and keeps things in a band arguably. So, that's why you -- if you look at the PSC affect, you might say, my God, gross barrels, it has, you know, $18 of cost, all in $30, what does that mean?

But the reality is that PSC affects as you go down, it tempers that but it also tempers the upside. It keeps you kind of where -- it keeps all parties happy, involved in this case.

But I think that the inventory here, especially with the PSC effects irrespective of price is, you know, 40 to 50 years of running room left on the reserves.

Obviously, we haven't done reserves at this end. But again, the PSC plays a different role here. And with prices going down, our reserves might actually go up. So, we just don't know how it runs at yearend.

Unidentified Audience Member

And when you talk about spending within cash flow, what's the expectation on production? Are we talking about, you know, because obviously next year, price is going to be higher if you look at strip. So, is that based off of higher prices and maybe lower production or flat production? How do you guys frame it?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I had to reframe in terms of what we anticipate the production rate is going to be as a result of the work?

Unidentified Audience Member

Yes. I mean, spending within cash flow is one thing, but what's the production profile to spend within that cash flow?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I mean, it varies from the workover to workover, obviously. But the VCI for those kinds of opportunities are the best that we have, so they're well in excess of three. The initial production rates is going to, you know, vary depending upon the opportunity. Sometimes, it's producing well where you're going to see rate impact almost immediately. Some places, it's recompletions to an injection well that takes -- may take several -- several months to a year before we start to see response.

Unidentified Audience Member

So, corporate wide next year, what's the expectation on production decline? Flat?

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

I think we're still working on that. I don't think we're ready to --

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Todd Stevens - *California Resources Corporation - President, CEO*

Yes. Basically, we want to live within cash flow when we've said that based on our initial calculations, running different scenarios, $500 million we can hold oil production flat to up next year is what we've -- what we're seeing.

What we've said too is, you know, Francisco has this big model and we can look out many years ahead and can we feel comfortable saying holding oil production flat out for a long period of time, I mean, that's why we said $600 million to $700 million and we're trying to, you know, a little bit is uncertain but we want to be right. So, that's why we gave you a broader range there.

But what we know about next year is we feel the 500 million -- some uncertainty, we want to see some stability in prices, what we're fortunate enough to have enough operating control where we can adjust on the fly here and be successful.

Unidentified Audience Member

Thank you.

Todd Stevens - *California Resources Corporation - President, CEO*

And I think we're already to the part where we have a general Q&A for everybody. So, we'll do that here for anyone who has any questions for anyone about any topic. Go ahead and please ask away.

Unidentified Audience Member

So, Todd, I guess this one is for you. A couple of things, going back to your earlier presentation, the 1.3 VCI was something you laid out very clearly. I think it was the western kind of incentive as well as -- the world's changed the law and you have a ton of inventory that doesn't work at 1.3 VCI. So, you're showing us, I think three years of inventory at 10 rigs, I guess it was, $55 oil if I remember --

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Todd Stevens - *California Resources Corporation - President, CEO*

I have to go back.

Unidentified Audience Member

Right. Right. So, what happens if oil is $55 forever? You're inventory doesn't work beyond that so --

Todd Stevens - *California Resources Corporation - President, CEO*

Well, that's -- that's a dynamic thing. I say living and breathing, you're going to go out there and you're going to work hard and do the things on both the cost side and on the process design side to make those things work.

You'll get a great example for what's happened up in the north of Mount Poso. I mean, there's some examples down here too but I think you adopted the environment. We go back and fight for our margins. I mean, the way we articulated is, you know, $100 oil, you had 50 plus percent margins. And now we're at $50 oil so we need to get back to 50 plus percent margins and however we do that is how we do that whether it's enhancing the differentials, cutting costs, cutting overhead, whatever we have to do, we have to get back and fight for our margins and that's what we will do.

Unidentified Audience Member

So, my followup -- my followup is the five to six -- $500 million number and $600 million to $700 million number, you've been talking about those now for quite a while, you know, at least in the context of CRC's lifecycle [in the company], oil prices were $60 at the end of, you know, I guess middle and second quarter that have come right down again and you haven't changed any in your number.

And so, what are you seeing in terms of service cost, additional cost reduction opportunities. Is that six to seven still the right number? Do you think that goes lower?

Todd Stevens - *California Resources Corporation - President, CEO*

Longer term? I guess we haven't -- well, we've just taken to account current costs at this point in time. I mean, you would talk, Frank -- I mean, service cost in those kind of -- in this environment, I think they've come down. But you got to remember, like our thermal steam floods, that's a 20% energy. So, it's natural gas prices, effectively, because the natural gas really is the primary driver on electricity and also the primary driver, you know, creating steam.

So, this is dependent on all those things but we feel really good and I think Bob would say the same thing. We've captured the vast majority of those for the long term through the cycle and we continue to work on that.

I think our -- we're not comfortable because we don't feel good about product prices but we're also -- we go to layer in the factor of we're probably going to execute one or more development slash and/or exploration JVs, so that's going to affect the capital program too. And so, we have to think about in the context of all that how it's going to ultimately work for us. So, it's a little more complicated than that.

Yes, sir?

Unidentified Audience Member

When you say $500 million for next year and then $600 million to $700 million ongoing, what are the primary differences between, you know, what comprises that $100 million to $200 million of additional capital?

Todd Stevens - *California Resources Corporation - President, CEO*

I think it's just uncertainty, more than anything. And, Francisco, correct me if I'm wrong, it's -- you have very good visibility on next year in your projects and you start talking three, four, five years out. Your visibility gets fussier and I think all engineers want to be right so, they're all going to add in that fussiness factored to make sure they're right and that's really what we're doing is there's a level of uncertainty so we want to make sure you're right out in the future.

To give you an example, I mean, when I was at OXY and we were in Yemen with Masila, everyone thought it was falling off that cliff a year from now and it get -- that year from now went on for like 15 years because that's just the way the engineers think. They really have good visibility short-term but, you know, out there in the medium term, it's harder and harder so they don't feel as comfortable but I think that's really what we're dealing with is just -- just the level of comfort and people putting a little bit of fudge factor, I'll say, in that to feel comfortable.

Now, there's also some facilities in there too. I'll say the real number in there, there's a little bit of facilities and the rest is, you know, just making sure they're right.

Unidentified Audience Member

There's no additional exploration, it's not, you know, you're -- you ran out of workover inventory so you're adding in more exploration or unconventional or anything happening --

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Todd Stevens - *California Resources Corporation - President, CEO*

No, I think right now, we have an enormous exploration portfolio. You'll hear about it tomorrow. But I think the idea there is that's something we have control over the spending right now and living within our means, we're going to balance and pull all the levers to do so and invest the money in way that creates the most value longer term and that's -- that's what we've been doing effectively now.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

There's one over here.

Unidentified Audience Member

Just two questions for you on that Page 17. The first one being there's a foot not about the economics does not include injectors. Could you just describe how that might change the economics?

Todd Stevens - *California Resources Corporation - President, CEO*

Which one? What are we talking about?

Unidentified Audience Member

It's the inventory slide that shows the -- at certain prices, how many rigs you can run?

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. Does not include injectors. From that standpoint, sometimes the injectors already exist or you're converting existing wellbore to an injector. So, the conversion cost, I don't know what the current going rate is, how much they cost in Wilmington to convert an injector to -- producer to an injector.

Frank Komin - *California Resources Corporation - EVP - Southern Operations*

It's going to be $500,000.

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. So, you're going to convert in that case for a pattern.

Unidentified Audience Member

Is there a way to think about that within the scheme of the inventory? Like, that's the cost per injector but how many do you use per --

Todd Stevens - *California Resources Corporation - President, CEO*

It depends. As Jerry was telling you, you know, you're going to -- especially in the Wilmington field, you don't have just the standard inverted 5-spot or 7-spot. You're going to try to accommodate to the subsurface and the geology that is given. So, it really depends.

In a lot of cases, you'll have -- injectors will have to be turned off or turned on. I think in Wilmington, obviously, it's more mature than anywhere else. But I don't think it really impacts the inventory materially.

Unidentified Audience Member

And then the last question, with that -- so this year you're only three rigs with $440 million of capital. This -- the plan where you have $500 million next year or $600 million to $700 million thereafter, how many rigs are you assuming are part of that?

Todd Stevens - *California Resources Corporation - President, CEO*

Right now, as you heard from Frank, we're more capital efficiently to drill more wells with the same amount of capital. So, the question is as we've said many times, we've run the business. We exclude the working capital that got stripped out of us at the spin-off, the free cash flow positive for the entire year, that's something we continue to do.

So, for us, if you want to add a rig, you're effectively adding $50 million at capital. So, the balance is do you want to do that or would you rather, you know, take that out of your revolver in the short term? So, that's the decisions we're making now as we go into end of the year as you've seen.

Generally, we've been underspending capital because we've been more efficient. And so, the question is we -- we're generating positive cash flow, what's the best use of those proceeds. And, you know, we'll look at our portfolio and determine, you know, what's the best thing to do or is it just paid out in the revolver but that's -- that's where we're at right now.

Unidentified Audience Member

And then what's the steps functions do as your approaching 2016, how do you think about adding rigs and is it combination of the asset sales and, you know, when --

Todd Stevens - *California Resources Corporation - President, CEO*

I mean, I think it's not so much driven by that. I think we're running scenarios where, you know, we can talk about a lower product price environment where we're at and we obviously saw we're hedged a little bit too, so we can talk about what will we do if product prices were in the lower environment, living within our means, and the we also talked about the higher environment and we also talked about all those environments we've layering on development, you know, a large development joint venture.

I think there's quite a few small one we're talking about folks that are meaningful to in the grand scope of things but it might be $10 million and $20 million dollars. But for hundreds of millions of dollars type joint venture, we'll talk about how to layer those on in different price environments and where would they work for us.

Unidentified Audience Member

Thank you.

Unidentified Audience Member

You know, just following on [Greg's] question on Page 17, maybe walk through the numbers a little bit for us.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay.

Unidentified Audience Member

To bridge to the $50 million. If we assume that the $55 example, that's $2 billion of capital. Doesn't that assume that at $700 million a year at the 10-rig program affectively?

Todd Stevens - *California Resources Corporation - President, CEO*

Of drilling?

Unidentified Audience Member

Off drilling. So, I guess, I want to understand then so that's - how you think about the cost per rig, how you get to $50 million incremental --

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Todd Stevens - *California Resources Corporation - President, CEO*

Well, it depends on the rig. I'm just being averaging out. So, it depends on the right. If it's a shallow rig, a deep rig, medium rig, you know, those kind of things.

Unidentified Audience Member

And maybe the second part of that is how we should compare that $700 million under this 10-rig program to the $500 million to $600 million you call for to maintain current production and then compare that back to what you're actually spending this year of or next year of the 400 versus the three rigs that would imply a 250 of cost.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. I think the thing to step back and realize that this is projects that have a greater than 1.3 VCI at those numbers. So, this isn't representative of inventory. And that's -- it's dynamic. It's like a snapshot today saying -- and if you looked at this slide relatively to the last time we showed this slide, it's actually changed a little bit because it reflects the work to date and that's been done by people.

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And so that's the thing is it's a dynamic living, breathing, and you know, next year at 55 after drilling, it could be higher, it could be the same. It's going to move around. And it's going to be a reflection of what we know at that point in time and that's what we're trying to do is as the projects get high grade and we move them into this category that is engineered and ready to go opportunities as opposed to, you know, just inventory by saying I'm going to drill up, you know, $100,000 acres on a five-acre spacing which you get from some people. They're just going to tell you there's this many wells.

We're trying to be -- to tell you these were actual locations on a map that are engineered and ready to go, not just some, you know, something on a chalkboard somewhere.

Unidentified Audience Member

Maybe let me -- I can simplify the question a little bit.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay.

Unidentified Audience Member

How much -- what does this exclude in terms of costs? This $2 billion to drill this many locations will also have incremental cost whether it's infrastructure, whether it's injectors, what would be the total capital cost and maybe I can bridge it that way.

And then the second question is just -- it's totally different -- the billion and a half you talked asset sales at the beginning of your presentation, it seem to imply what's basically going to come all from midstream, is that -- am I reading it wrong?

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. Going back, I believe -- and Francisco, correct me if I'm wrong -- this is -- this includes all the capital, right, for this?

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

(Inaudible -- microphone inaccessible).

Todd Stevens - *California Resources Corporation - President, CEO*

Drilling associated with all these but this has workovers --

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

Coorrect.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay.

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

So, yes, it includes new wells and workover capital.

Todd Stevens - *California Resources Corporation - President, CEO*

Capitalized workovers. Okay.

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

Right.

Todd Stevens - *California Resources Corporation - President, CEO*

So, this is capitalized workovers and new wells. So, this is -- this would include how much more approximately facilities? I guess it depends on the product price --

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

It depends on the projects, you know, the steam floods, we have a lot of the infrastructure in place and we have a lot of injectors in place with selective drilling or selective injectors that come in to enhance the production of those projects.

So, it depends but, you know, on average, we've been -- I think our average has been about 30% facilities cost and if you look back at [prior] programs, so that's a rough estimate that you can have on top of that to get this projects moving.

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. And that -- that varies, I think it's come down. But if you were talking about greenfield, the most cases we're adding patterns, we're not adding a brand new greenfield project so that's typically less.

But if there's a new greenfield project, facilities is usually about 30%.

Francisco Leon - *California Resources Corporation - VP - Portfolio Management & Strategic Planning*

About 30%. Right.

Todd Stevens - *California Resources Corporation - President, CEO*

Okay. And the other part about -- you're talking about the six or seven -- the midstream. So, I was just articulating what I felt where we are today because our goal is to raise that kind of proceeds, $1 billion, $5 billion, $6 billion and when I look at all the opportunities and levers we can pull, it just seems like it makes the most sense to if you could say I can raise this from an upstream when upfront but I rather have that plowed into the ground as opposed to if I could do it out of the midstream segment at this point in time.

You'd rather not monetize for cash up front. I'd rather monetize upstream from the standpoint of bringing -- of working interest partner that's going to invest in the project and create value longer term.

Unidentified Audience Member

From a joint venture interest perspective, can you talk a little bit the county level regulatory flux? Have you seen people that want to come in and do something with the focus on current county where it might be perceived as a little bit safer?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. We think about joint ventures. Frank's spent a lot of time talking about down here with the production sharing agreements you see in Long Beach, that's fairly complex. It would be not impossible, you know. It's one of those -- it's possible, not probably to bring up a potential partner. So, we've stayed away from that and really focused on Ventura, San Joaquin and Sacramento basin.

And I'll say we have interest in all of the above -- above all drive mechanisms in unconventional and conventional, you know, really, across the board when you think about it. And again, I know some people don't believe that we do have actual interest in the Sac basin too. People want to go up there and drill some gas wells. [Doug]?

Unidentified Audience Member

So, just a followup to that. You and I have traveled earlier this year, you'd said that folks are going to be shocked at the level of signature bonuses that you think you can achieve in some of those joint ventures? And if I heard you correctly, you've just said that you don't really want to take cash upfront. You'd rather see that reinvested. Can you reconcile those three comments?

Todd Stevens - *California Resources Corporation - President, CEO*

Yes. I think -- it's a dynamic thing you're trying to do what's best, you know, trying to optimize things. And that point in time, you know, when you -- when you were talking to folks and you felt like maybe it was more, you know, an opportunity to take more cash off the table by doing something on the upstream side and now when you analyze it from an overall shareholder perspective, it just seems better to plow that money back in the ground and extract because of the valuations and the opportunities set on the midstream site.

Yes, sir?

Unidentified Audience Member

On your deleveraging slide, you talked about upstream and midstream opportunities but also capital markets is listed as a third prong, can you just talk about what you mean by capital markets? Is that something on the order of debt buyback in the open market that exchanges into equity or secure debt? Can you just talk about your thoughts --

Todd Stevens - *California Resources Corporation - President, CEO*

Well, we're limited by, you know, our tax sharing arrangement with Occidental. And, you know, and I've said many times, you know, I view that equity is more of a last resort at this point because we have so many levers to pull.

But, you know, if our debt traded into the 50s, you have to, you know, start trading distressed, you have to start thinking about what are the capital market solutions there. If our equity traded much higher or if we could issue equity, you know, you don't have to analyze all those things, to be intellectually honest with yourself and you don't want to preclude any opportunity that might be out there. I just don't think they're highly probable. But, you know, you really want to canvass and make sure you've exhausted everything that could make sense for the shareholders.

Unidentified Audience Member

And how much of secure debt is available in the capital structure under the indentures to that?

Todd Stevens - *California Resources Corporation - President, CEO*

Four billion.

Unidentified Audience Member

Thanks.