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A review of November 24-25, 2011 shale gas workshop, Calgary, Alberta – 1. Resource evaluation methodology

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DISCLAIMER

This document is an informal discussion paper based on the personal views, ideas and concepts of participants attending the shale gas workshop, and in some cases, the views of their organization. The observations and recommendations contained herein do not necessarily reflect the opinion of Natural Resources Canada or the Government of Canada, or those of the other departments and organizations identified in the document. Notes from the round-table discussions have not been reviewed by the agencies represented at the workshop, however, the workshop participants were aware the notes would be published. This document is a working draft for discussion purposes.

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INTRODUCTION

Shale gas is one of the hottest energy resources in North America, as improved completion and production techniques are unlocking huge volumes of natural gas. In Canada, production is increasing rapidly in British Columbia and almost all provincial jurisdictions have shale targets currently being explored and evaluated with highly variable technical and societal successes and issues.

Recognizing the importance for the Canadian economy of these major resources, the Earth Science Sector of Natural Resources Canada has initiated a reflection on its potential implication in this new research area and how its Geological Survey and the provinces/territories can collaborate on addressing the geological and societal concerns regarding the extraction of the shale gas resources.

A preliminary workshop was held in Ottawa in May 2011 with various issues being discussed by public geoscience, academia and industry stakeholders. From a geoscience point of view, two major items were agreed upon: 1) the need for a scientifically sound methodology to evaluate the in-place and producible gas in continuous resources such as shales and 2) the need of geoscience knowledge for improving groundwater management and protection. To address the two issues raised from the last shale gas workshop, the Geological Survey of Canada organized this second workshop on Canadian shale gas. The workshop was divided into two sessions: one emphasizes the methodology issue on shale resource assessment, and the other focuses on the groundwater issue. For the methodology session the objectives include 1) to review the methods that are available or are in use for Canadian shale gas resource assessment; 2) to discuss the nature of the shale gas resource and the parameters that should be considered in the methodology.

Two keynote presentations were made on resource assessment methodology with application examples by representatives of the National Energy Board of Canada and the Alberta Energy Resources Conservation Board (Appendix B and Appendix C), representing current Canadian approaches of the federal and provincial governments in shale gas resource evaluation. Discussion was followed after the two keynote presentations.

This document summarizes the discussions on various issues associated with the methodology. The two presentations with annotation comments are included in this report as references. It should be noted that presentations focus on areas (northwestern British Colombia and Alberta) where the amount of geological and geochemical information is among the highest in Canada. Moreover, presentations discuss shale gas plays that have been buried enough to generate thermogenic gas. For this reason, the methodologies describe in the presentations may be not directly applicable to others least studied shale intervals or to biogenic gas plays.

BACKGROUND

In Canada, huge volumes of in-place and recoverable shale gas resources have been reported by the industry and consulting firms. However, the methodologies used for the resource evaluations are rarely detailed and, for this reason, the estimates remain to be confirmed. In 2011, the National Energy Board released the first probabilistic resource assessment of a shale gas play in Canada done by a governmental agency.

For many years, Natural Resources Canada and its Geological Survey had carried out resource evaluations for conventional hydrocarbon plays. However, the methodology to evaluate the conventional resource cannot be applied to these unconventional continuous resources and the in-place and recoverable resources claimed by the industry cannot be independently verified. The November 2011 Calgary workshop aimed at gathering federal-provincial-territorial public natural resources and energy stakeholders to discuss on the best methodological approach to evaluate the Canadian shale gas resource to be performed independently by Canadian governments.

Technology and knowledge gaps in existing methodology

The knowledge and technology gaps arise from the emerging nature of Canada's gas shale resource development. First of all, the concept of shale gas is new to most Canadian geoscientists. Shale was previously regarded as a source rock in conventional petroleum plays and it is now considered as a hydrocarbon reservoir, from which commercial gas can be extracted with new technology. The intrinsic characteristics of the resource and the fundamental controls on its productivity are not yet well understood. Second, the development and production history from this type of emerging resource plays are short and there are few production wells in Canada with a history of well performance that can be used to extrapolate recoverable potential. Third, shale gas productivity depends on the type, intensity and number of fracture stimulations in the reservoir. This technology is new and major uncertainties reside in the volume of gas that can be extracted from shale. Similar uncertainty exists as to the best practices for applying different stimulation techniques, and how future technological development will affect productivity of wells. Fourth, the data availability for shale gas assessment in Canada is highly variable, from tens of thousand modern wells in the Western Canada Sedimentary Basin to a handful of wells in other shale units identified in Canada. A comprehensive, consistent, repeatable and standardized approach to evaluate shale gas resources and independently validate industry resource potential claims is required to meet the needs of policy and economic decision makers.

A resource evaluation methodology

The design of a new methodology has to be based on the characteristics of unconventional continuous resource play, state of exploration and development of shale gas plays (geological and production data availability) and the needs from various stakeholders in Canada. Convenience in updating the assessment when new data become available is also a feature that will have to be considered in the new methodology. Because shale gas exploration and development are relatively new in Canada, there are limited production data available for extrapolating well performance and many shale basins are mostly unexplored with little geological, geochemical and geotechnical information. The assessment methodology for continuous resource must be flexible enough to adapt to situations ranging from little or no well data to thousands of production wells.

Unconventional resource plays are very different from conventional plays. During the early phase of development, the in-place resource is the most reliable estimate and predicting recoverable factor from shale play is difficult as it involves various geological and engineering factors and will add considerable uncertainty to the estimates. However, estimates of recoverable portion of the resource under the current technology are also important for various government partners and stakeholders to address challenges related to social license to operate for shale gas development. Because of additional development costs related to well stimulations, economic margins could be very thin and business success often depends on early identification of favourable areas. Therefore it is crucial to provide resource estimates to outline favourable areas, even if recent well or production data are scarce or lacking.

DISCUSSIONS

Some of the themes that were discussed included, amongst others: overall volume of continuous shale versus that of the economic "sweet spots", geological parameters to be eventually integrated in the definition of a shale play for resource evaluation (organic matter content and its origin, minimum and maximum thermal conditions, shale thickness, gross to net ratio, depth and pressure conditions, porosity, saturation and permeability values), and free versus adsorbed gases.

Day 1

The discussion started by the identification of basic geology data and a review of the history of production. Cross-referencing those points could be used to make analogues for comparison, and the result will not be identical, but could lead to helpful hints.

Discussions focussed on some specific points:

- Are regulations adequate for capturing data required for good resource management?

- What is the plan for provincial revenue?
- Are wells suitably instrumented?
- To what extent should class of research well be distinguished to collect data?

Any data captured and collected along the way should in theory, be available for the provincial regulators. Some of the discussions led to consensus among participants.

1) Methodology

Production based methods like the one used by the United States Geological Survey are not reliable until a certain knowledge of the play is achieved and significant amounts of production data are available. Considering the limited production data in Canada in a few of the prospective shale plays, such methodology is not suitable.

Moreover, the assessment methodology for continuous resource must be flexible enough to adapt to situations ranging from little or no well data to thousands of production wells. It should maintain the link between resource evaluation and geological parameters.

2) Resource estimate terminology

Resource estimate terminology should be as clear as possible. Use of a homogenous terminology among governmental agencies would help stakeholders to compare the various resource estimates.

3) A good geoscience framework is needed with modern maps, wells and good understanding of sedimentology and stratigraphy

This is the basic information upon which specifics to shale plays will be added. This geoscience knowledge is the traditional bread and butter of the GSC and provincial geological surveys. Abundant information is already available for some specific basins, although, minimal data characterize much of the northern shale basins. Upgraded and new data are needed.

4) Reservoir pressure and temperature data are required

This information has first order significance to the calculation of hydrocarbon storage capacity of shales as well as on their delivery potential.

5) Core data should be used to calibrate seismic and log data

Whenever is possible, it is highly desirable to correlate the geophysical data to real physical (core) information. However, the differences of scales as well as sampling bias (e.g., black vs grey shales for TOC for example) have to be considered when interpreting the data.

6) Other public datasets should be made readily available

Provincial jurisdictions are responsible for gathering industry data, but confidentiality conditions / period vary from one jurisdiction to the other. Every effort should be made to allow access to industry data as the federal/provincial geoscience organizations and regulators cannot generate most of the high-cost data produced by the industry.

7) Mineralogical aspects of shale and links with resistivity

Mineralogy is one of the fundamental variables in the evaluation of a shale succession. The relative abundance of silica, carbonates and clays will control the shale brittleness as well as affect the well production performance. The GSC has the technical capacity to play a fundamental role in that field.

8) The importance of types of organic matter and understanding its porosity evolution with burial

Significant volumes of gas are adsorbed in organic matter and will contribute to the ultimate recovery of specific wells and plays. The understanding of the nature and evolution of that pore space during burial and thermal evolution of the organic matter is a highly active research field. The GSC has developed a world-class expertise in organic matter over the years and this expertise has to focus on that important aspect of shale plays.

9) Grain density

Grain density is an important element in the interpretation of geophysical well logs. One aspect of future research should be directed to the specific recognition and significance of organic matter on the grain density evaluation.

10) The shale porosity and permeability couple

Even if relatively low, the porosity of a shale succession is important for its storage capacity of free gas. In the early phases of production, most of the gas released by the stimulated shale comes from that pore space. It is critical to understand its nature (primary vs secondary), its diagenetic history (presence of swelling clays? or other specific mineralogical phases) and its distribution in a shale succession. Permeability is less of an issue; today the industry will successfully fracture shales with nano-darcys permeability.

11) The adsorbed versus free gas issue

In shale plays, gas occurs in two modes: adsorbed on organic matter within the shale bed and free in porosity within the shale matrix. Determining the percentage of each mode is important for resource assessment as desorbed gas diffuses at a lower pressure than free gas.

12) Cut-off values

Definition of a play area implicitly refers to cut-off values for some of the parameters used during the resource evaluation. However, experience gained in the United States shows that cut-off values may vary significantly from one area to the other, with improved geological knowledge and with new innovation in drilling and completion techniques. For example, the upper cut-off value for organic maturity becomes elusive as shale intervals that were deeply buried may still have some economic potential even enhanced from late stage gas generation. Analysis of US shale play characteristics may help to fix minimum and/or maximum values for some of the parameters used during the resource evaluation, although with the constant reminder that likelihood of perfectly similar shales are very small.

Day 2

1) Hydraulic fracturing

Discussions were initiated on the potential implications of the Geological Survey of Canada in the research on hydraulic fracturing. Hydraulic fracturing choices are dictated by the mineralogy, and providing mineralogy has been on the GSC fundamental role over the years. GSC should provide good integrated data sets by collecting data on individual wells and then tying data to production. GSC should identify an ideal geoscience workflow to develop good mineralogy to guide hydraulic fracturing decisions.

XRD provides semi-quantitative data whereas SEM provides more data and the exact mineralogy of clay plates although the latter being more expensive.

2) Shale oil

The workflow to be developed for a resource assessment methodology should be flexible enough to be applicable to shale or tight oil. Moreover, characterizing the gas-oil ratio (GOR) is important because oil can affect gas productivity in tight formations.

3) In-place vs recoverable volumes

The GSC has carried out quantitative resource evaluation for conventional hydrocarbon plays. The resulting resource assessments were presenting preferably as the in-place numbers in probability distributions or specific percentiles (P10, P50, P90). To the contrary of the USGS, no recoverable volumes were given. For shale plays, it is critical to contextualize all data provided. However, in unconventional resource assessment, in-place numbers should not be provided in isolation because only a very small fraction of the in-place resource can be economically extracted under the current available technology. In-place volume stand alone, sometimes, could be misleading. People should realize that recoverable factor may vary considerable from resource play to play depending on the geology and stimulation techniques applied, and a trend of improving recovery through time has been documented in several basin due to a better geological and geotechnical understanding of the shale and the availability of new and more efficient technologies. A range of recoverable volumes could be presented from an optimistic (high end) scenario to a pessimistic (low end) scenario. In the event that governments and regulators ask for specific numbers, a conservative approach of recoverable resources should be followed.

4) Test well and research consortium

A discussion about the role of test wells led to a debate on the scale of such operation. Test wells could provide both geoscience and environmental data but needs have to be prioritized. Possibilities range from building a major industry-government-academia consortium like the one in place for the Weyburn project, to small scale but more flexible operations. The former would, over a longer time frame, provide some in-situ information for a specific shale and/or area whereas the latter could provide some basic stratigraphy, sedimentology and other rock information for a significant number of shale plays. Some provincial jurisdiction, like the OGS, are already providing sub-surface information with an active drilling program whereas, in other jurisdiction, the quantity of drilling information makes the small-scale operation largely useless.

In the establishment of a consortium, it is important to have a large number of participants in order to avoid the risk of being considered a subsidy for a company. The U.S. Joint Research Projects are a very successful model. They convene a work group, determine the science problems to be addressed by a well, accept gifts-in-kind, and offer pieces of the production. However, confidentiality questions have to be negotiated before anything else.

5) US shale gas characteristics

A rigorous analysis of major US shales geological, geochemical and geotechnical characteristics may be used for a preliminary evaluation and categorization of Canadian shales. With the industrial development of US shales, a huge amount of new information on shale plays is constantly released in the public domain. With the increasing number of shale formations studied, the potential analogue spectrum widens.

As each play has its unique geological, geochemical and geotechnical characteristics, the aim of the analysis of major US shales is not to find a ‘perfect duplicate’, but rather to examine the critical parameters that influence shale gas development and to use the more appropriate range of values for such parameters.

CONCLUSIONS

One of the main aspects discussed during the workshop was the need of clear terminology as it is important to make sure that numbers from an unconventional resource assessment that are circulating in the public domain are well understood as these impact public perception and eventually the legislators. A clear distinction has to be made between in-place and recoverable volumes, resources versus reserves. Average recovery factors are between 20–30%, with some operators claiming higher ratios in some areas. With better understanding of geology and the hydraulic fracturing process to stimulate the wells, the assumption is that the recovery factor will improve over time. Recovery factors and recoverable resources will change with the evolution of the basin. Federal and provincial jurisdictions need to be able to independently evaluate the economic potential of their shale plays.

Recoverable resources are a fraction of gas in place; this recovery data can be estimated from real-life experience. In basins with no data, a different approach is used. Analogs such as compiled by the United States Geological Survey used in the evaluation of frontier basins are possible. The reliability of analog recoverable factor depends on the selection of the analogous basin. In some circumstances shale formations may look similar and yet differ in the type of pore space, organic matter, or pressure regime. A solid geological framework is necessary for effective analysis.

Modern geological information, beginning with maps, is needed; vast areas of Canada are poorly mapped, having been originally mapped in the 1950s by the GSC and provincial surveys. In the past, maps were not focused on shale formations, and shale stratigraphy is poorly understood in many prospective areas. The subsurface information is essential to a sound evaluation of the shale plays: well data (core, cuttings, logs) and seismic will provide the critical information that should be integrated in the resource evaluation workflow. An understanding of burial exhumation conditions, to model pressure and thermal regime will create a sound framework that gives detailed information on basin evolution.

The identification of the type of organic matter is important, as they are not equal in their potential to generate hydrocarbons; Types 1 and 2 are most important.

Porosity is critical in evaluating shale gas, accessible through logs or by petrography, as it will control the volume of free gas rapidly delivered from a shale unit. Basic geological work gives information about origin of porosity and about the type of material in the pores.

The development of a useful methodology will require a workflow to generate a suite of meaningful data. This may be expensive and time consuming. Today, the only shale gas resource evaluation in Canada performed by government agencies is the one released by the NEB and British

Columbia Oil and Gas Commission for the Horn River Basin in NE British Columbia (B.C. Ministry of Energy and Mines, National Energy Board, 2011). The approach to resource evaluation is based on a probabilistic volumetric approach, differing from the recent USGS approach which is based on well performance (Charpentier and Coke, 2011). Canada does not yet have enough information to generate the numbers (Estimated Ultimate Recovery – EUR) for a statistical methodology.

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Appendix A: List of participants in the methodology session

	Name	Affiliation
1	Steven Hinds	Department of Natural Resources, New Brunswick
2	Andrew MacDonald	Petroleum Resource Division, Nova Scotia Department of Energy
3	Catherine Béland-Otis	Sedimentary Geoscience Section, Ministry of Northern Development, Mines and Forestry, Ontario Geological Survey
4	Michelle Nicolas	Manitoba Geological Survey, Manitoba Innovation, Energy and Mines
5	Pamela Fulton-Regula	Petroleum Branch, Manitoba Innovation, Energy and Mines
6	Melinda Yurkowski	Subsurface Geological Laboratory, Saskatchewan Geological Survey
7	Steve Lyster	Energy Resources Conservation Board, Energy Resource Appraisal Group, Alberta Geological Survey
8	Andrew Beaton	Energy Resources Conservation Board, Energy Resource Appraisal Group
9	Jeff Johnson	Ressource Development and Geology, British Columbia Oil and Gas Commission
10	Mark Hayes	Ressource Development and Geology, British Columbia Oil and Gas Commission
11	Adrian Hickin	Ministry of Energy, Mines and Petroleum Resources Resource Development and Geoscience Branch, British Columbia
12	Filippo Ferri	Senior Petroleum Geologist, Geoscience and Strategic Initiatives Branch, B.C. Ministry of Energy and Mines,
13	Tiffany Fraser	Yukon Geological Survey
14	Keith Hynes	Director Petroleum Engineering, Government of Newfoundland and Labrador, Natural Resources
15	Deborah Archibald	Director - Minerals, oil and gas, Northwest Territories
16	Mike Johnson	National Energy Board, Calgary
17	Gary Woo	National Energy Board, Calgary
18	Peter Budgell	National Energy Board, Calgary
19	Jim Davidson	National Energy Board, Calgary
20	Giles Morrell	Northern Oil and Gas Branch, Aboriginal Affairs and Northern Development Canada
21	Nicolas Pinet	Commission géologique du Canada (CGC-QC)
22	Tony Hamblin	Geological Survey of Canada (GSC-Calgary)
23	Kirk Osadetz	Geological Survey of Canada (GSC-Calgary)
24	Fred Wright	Geological Survey of Canada (GSC-Vancouver)
25	Denis Lavoie	Commission géologique du Canada (CGC-QC)
26	Zhuoheng Chen	Geological Survey of Canada (GSC-Calgary)

Appendix B: Presentation by Mike Johnson of NEB

Summary of a report release on May 6, 2011

Acknowledgments:

Companies, industry groups, and individuals who participated in the consultation phase,

United States Geological Survey,

Geological Survey of Canada,

Southwest Statistical Consulting

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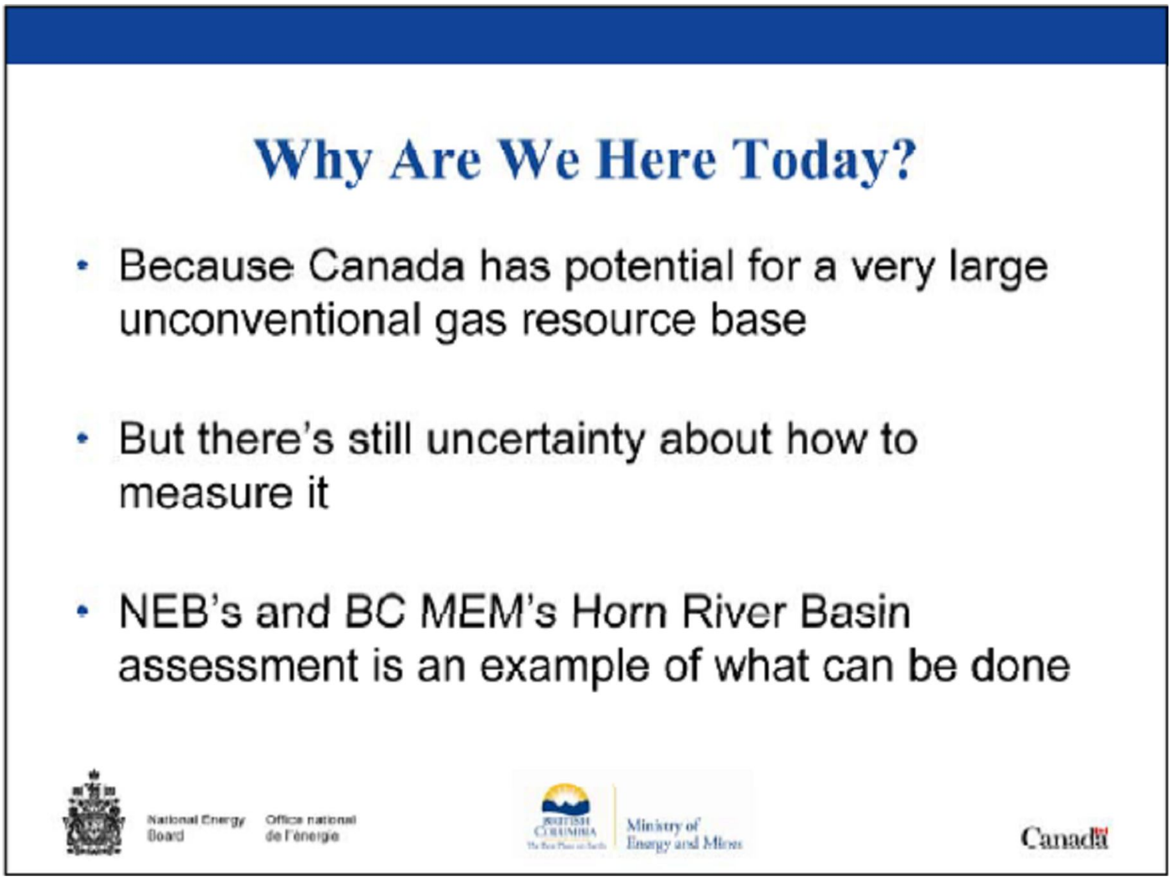


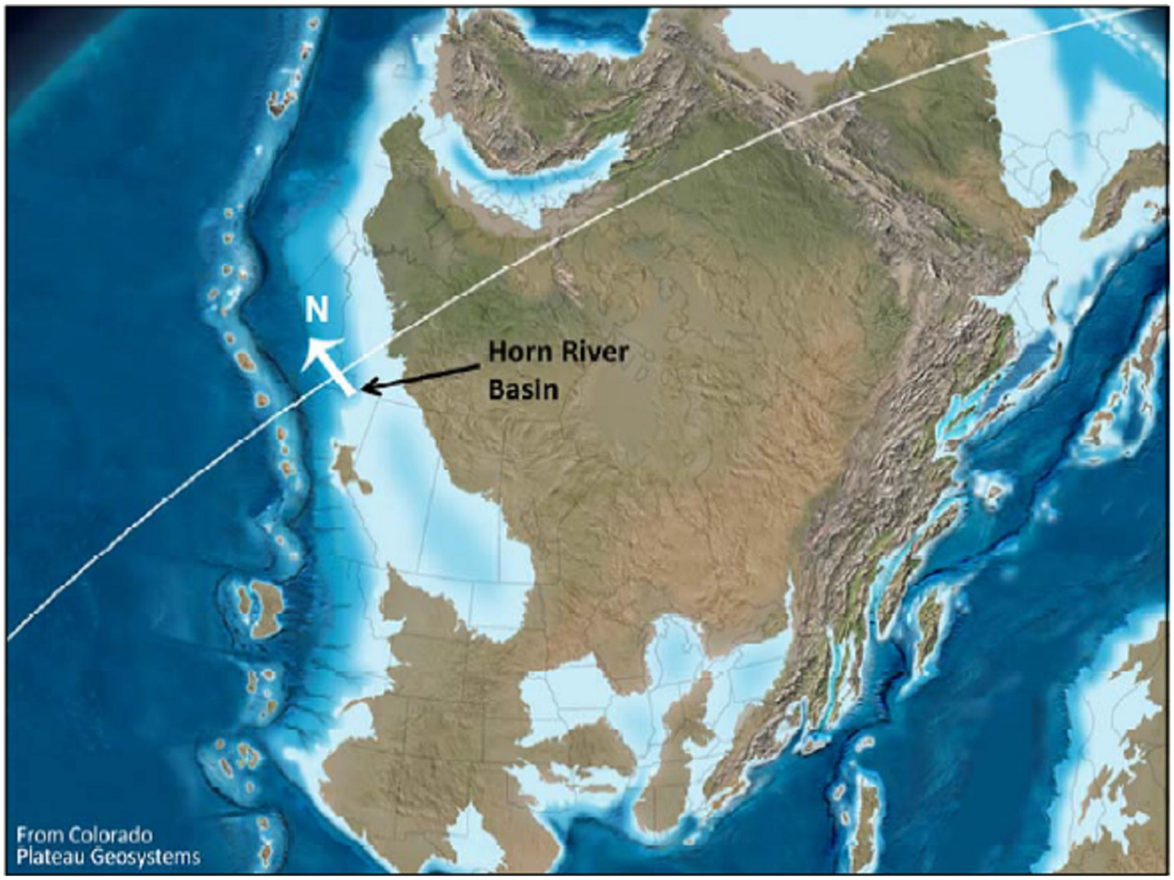
Unconventional not just shale gas, but Coal-Bed-Methane and tight gas as well.

Big uncertainties in how to measure the resource: Gas In Place and then apply a Recovery Factor? Use type production curves and estimates of wells drilled per section? How much uncertainty is there in the estimate itself? Low and high?

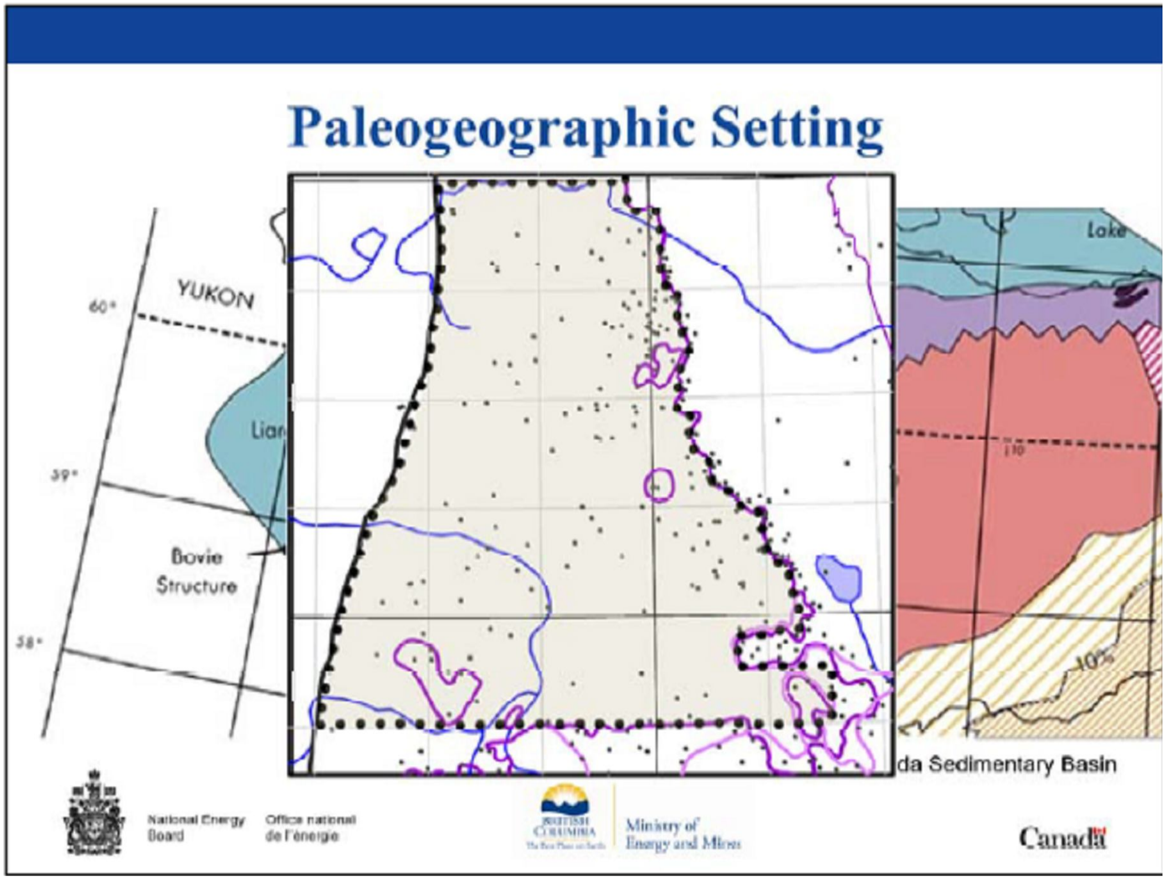
One technique for one may not work for another: may depend on data available, for example. No production data, not type-curve based assessment.

As part of its mandate under the NEB act, the NEB performs resource estimates to gauge the amount of gas resources there are in Canada. The NEB act hasn't changed recently, but industry's ability to tap unconventional resources has, which meant we had to find some way to include unconventional resources in these resource assessments.

Will cover our methodology as well as discuss some of the challenges we faced.

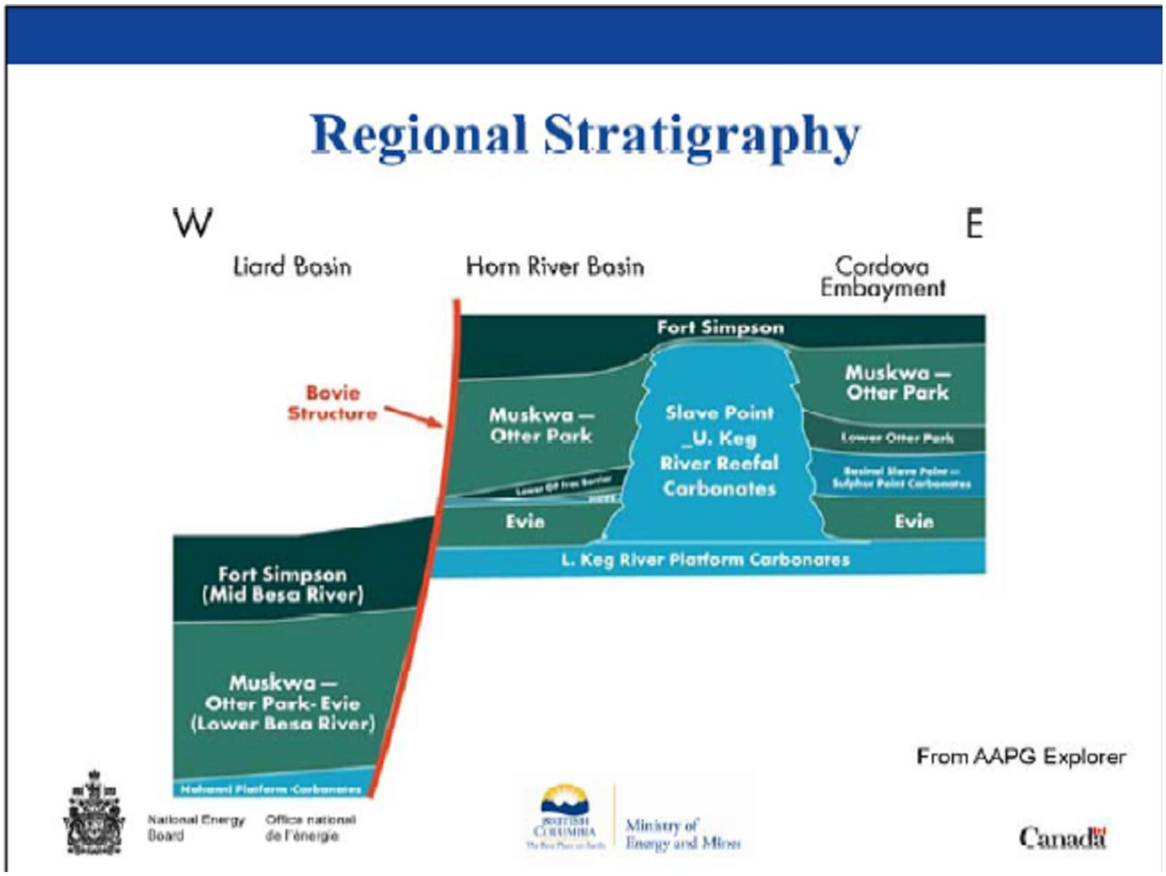


This map illustrates the paleogeographic setting in the Mid-Devonian, about 380 million years ago. Western Canada is located south of the equator. There's a broad carbonate shelf reaching deep inside western Canada, fringed by reefs at its seaward edge and deeper waters westwards.



The Horn River Basin bounded on its east and south side by the Presqu'ile Barrier Reef of the Upper Keg River and Slave Point formations. On its west side it is bounded by the Bovie Fault. There are two sister basins that were not assessed but also have shale-gas potential: the Cordova Embayment to the east and the Liard Basin to the west. The Horn River Basin extends into the NWT, but was not assessed because of the lack of shale-gas activity.

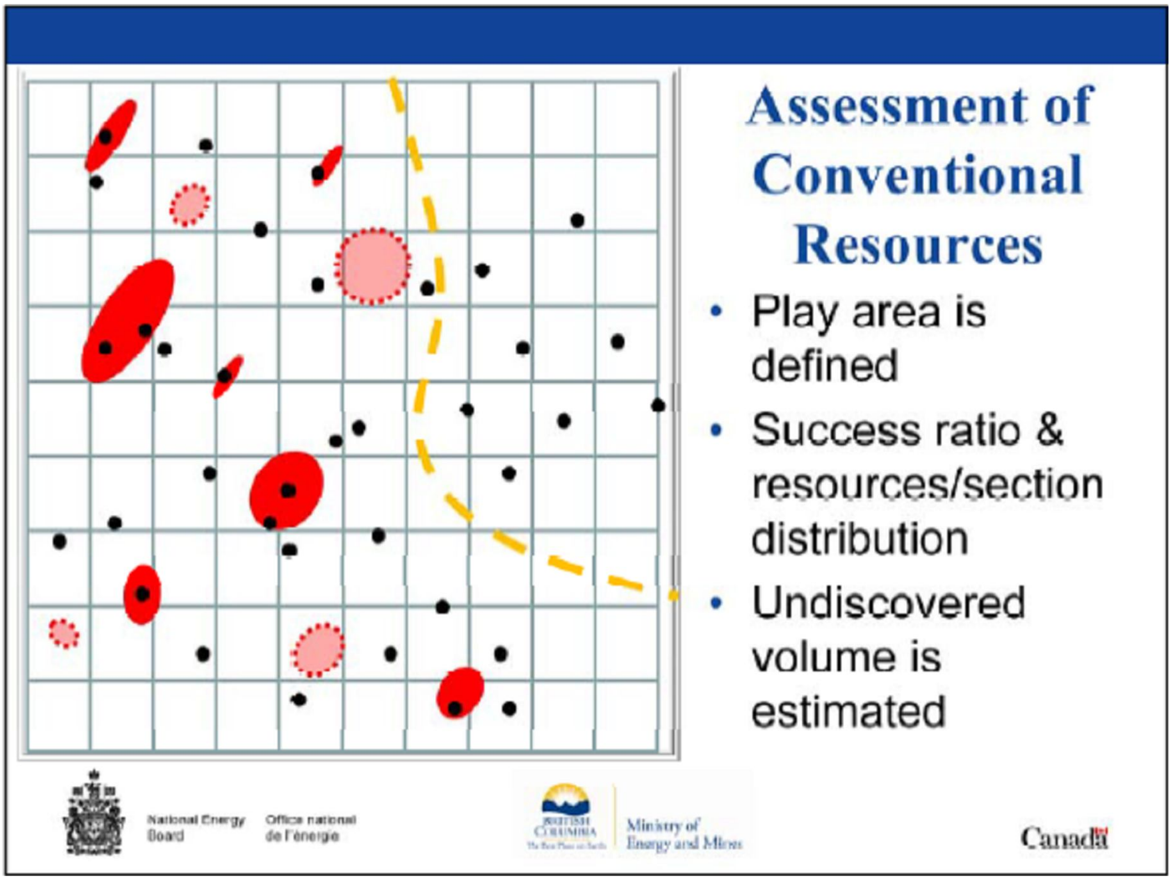
The dots are well control.



The stratigraphy of the Horn River Basin shales is pretty layer cake. The Evie Shale and then Otter Park Shale were deposited contemporaneously with the Keg River and Slave Point reefs. Then rapid sea-level rise drowned the Slave Point reefs and the Muskwa shale was deposited over top of it.

Each of these three shales is organic-rich and brittle, and were buried deep into the gas window, which makes them prospective for shale gas. Thus each had to be evaluated for the study.

Note that the Muskwa shale is spread over much of western Alberta, where it's known as the Duvernay Shale, also prospective for shale gas, as well as shale oil.



This is generally how we approached resource assessments on a conventional reservoir.

1- The area is broken down into tracts (based on drill-spacing units, or sections).

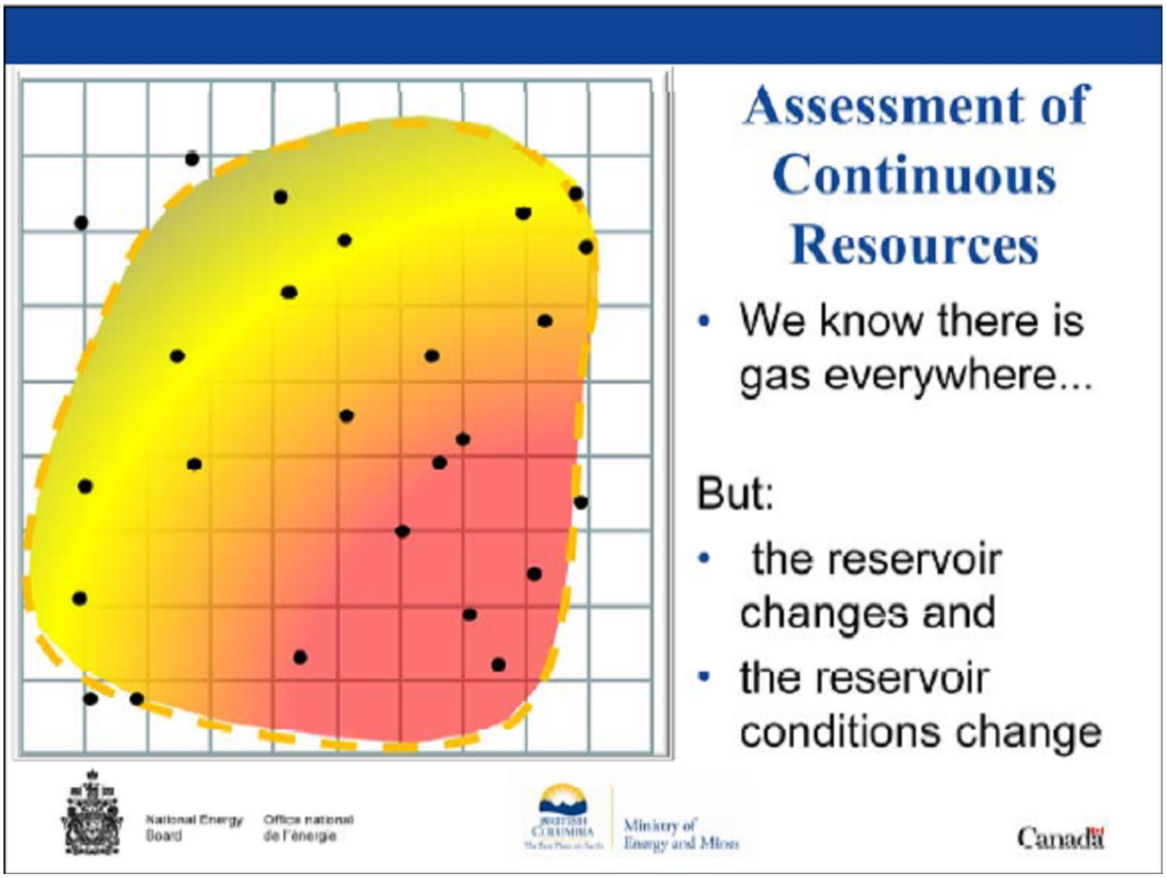
2- The play area is defined using edges (the dashed yellow line) and discoveries are identified (Dark Red pools)

3- Success ratios are determined based on historical data, i.e. how many tracts had discoveries in them out of the total number of tracts where the formation was drilled into (Black drill markers)

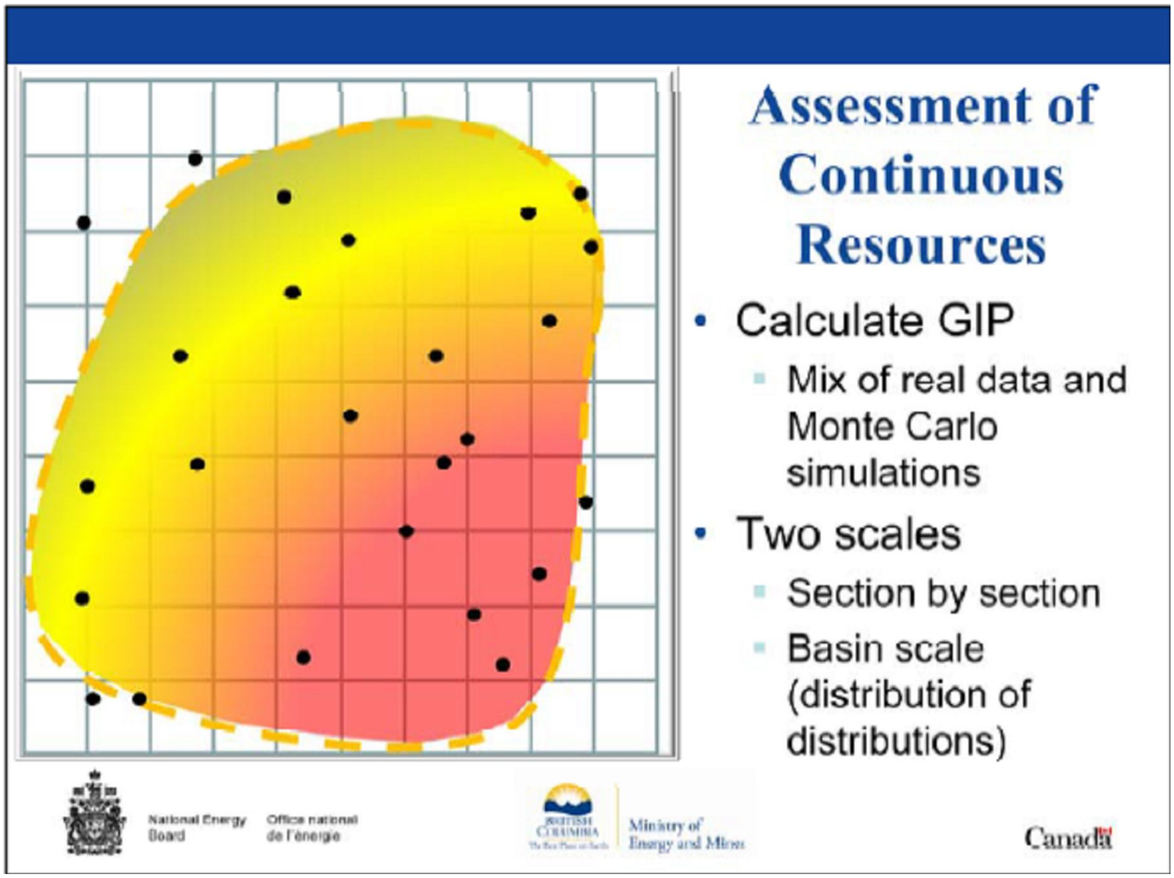
4- The success ratio is used to determine the remaining number of discoveries to be made in undrilled tracts. (Light red pools)

5 - Using a Monte Carlo simulation to estimate the undiscovered discoveries in remaining undrilled tracts, the resources are estimated by using a distribution of resources/tract as derived from existing pool data.

Of course, this only works if you have enough historical reserves data to go on. Or, if you have multiple pools from which to build a distribution of resources per tract.



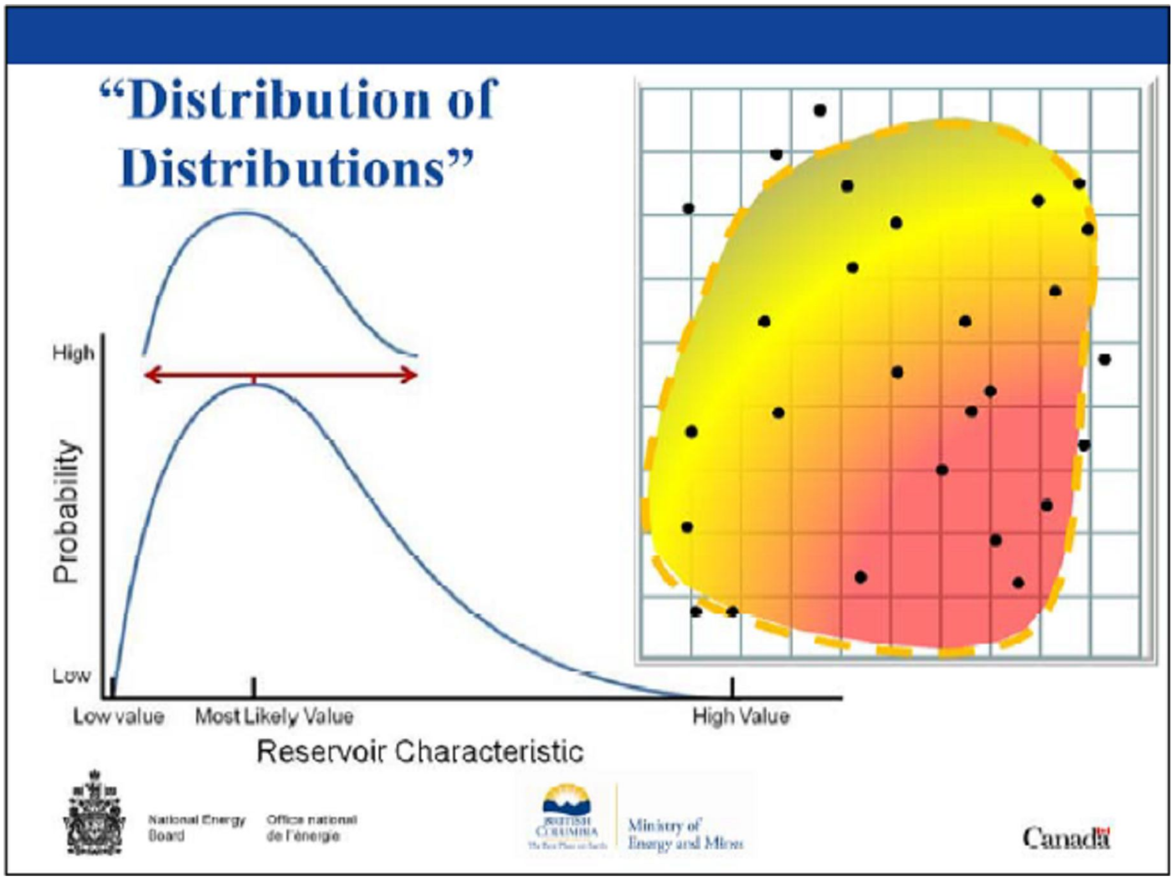
Continuous resource plays, like shale gas, must be approached differently because they're like one big gas pool, the gas pervasive throughout the play area and wherever you drill a well into it. Success rates can easily be thought of as being 100% (technological success, not necessarily economic success). Further, the reservoir conditions can change dramatically across a play area. The Horn River Basin stretches for about 150 km from one corner to the other and covers over 4000 square kilometres. We incorporate maps into the resource assessment because of this variability and we treat each shale section as its own pool. Success rates are set at 100%. That's not to say they'll always be 100% in a resource play: success rates could be less in marginal areas, though still expected to be high.



The maps are based on well data, such as reservoir parameters like thickness and net pay. The maps are grid based, where each grid point represents a section on the map.

Where the data is "real" behind a reservoir parameter (i.e. the section has real data attached to it through a well), the point becomes hard. For sections where the data is not available, we can use statistical methods to fill in the gaps and the value is allowed to vary to simulate uncertainty section by section.

These maps have to be forced to vary in their entirety as well: what we've mapped is really a best estimate. In reality, we'll probably be close, though not 100% correct, and once the basin is drilled up the results could be lower or higher in reality. By modifying things at the basin scale, we can essentially simulate a suite of maps that are mapped pessimistically to optimistically, increasing uncertainty.



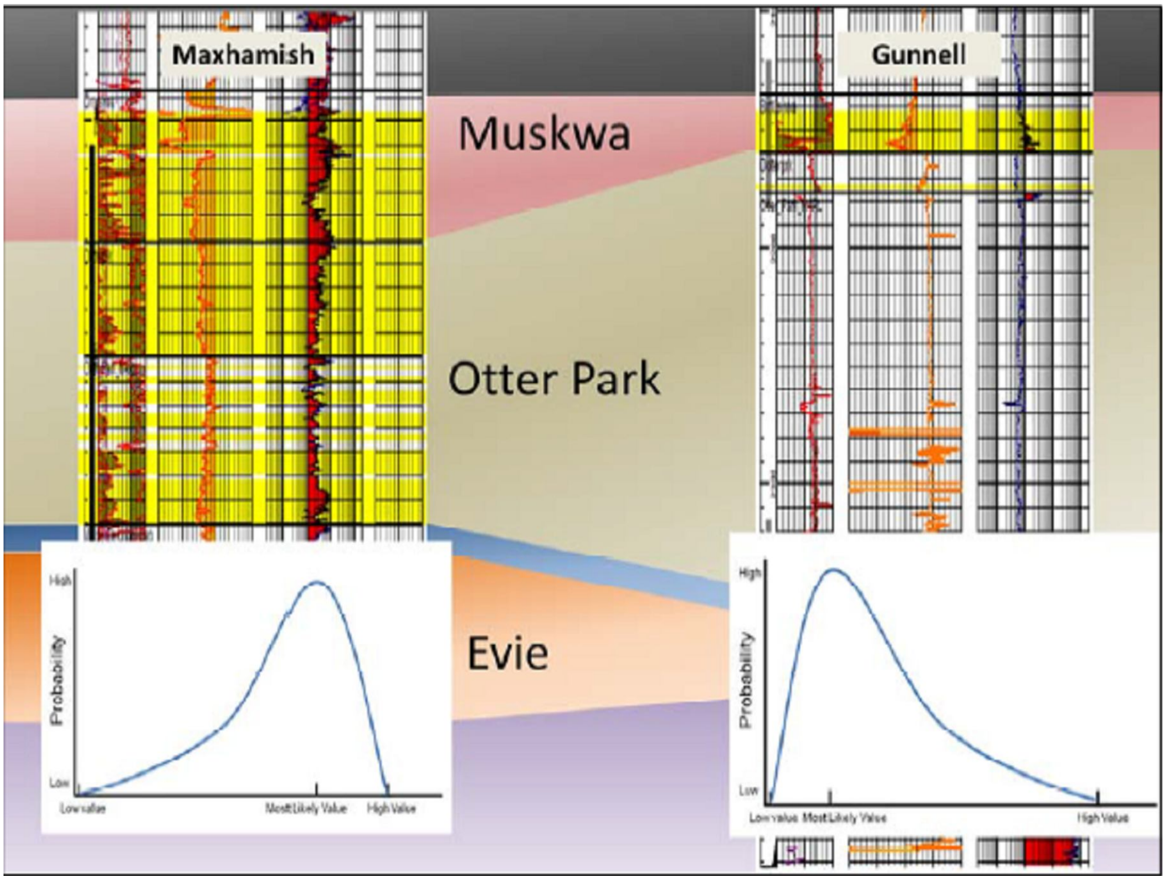
So how do we get a map to vary?

Like mentioned, where there's a well with relevant data, the grid point becomes static and no distribution is applied.

Where there is no well, each grid point has a distribution applied where grid point becomes the most likely value in a distribution. Upper and lower values around that distribution are based on high and low points for the basin. That's section by section.

To apply a basin-scale variability, we apply a distribution of distributions, a term from USGS staff as they were describing some of the techniques they were using for their own shale-gas resource assessments. When determining resources on a section by section basis, unchanging probability distributions (i.e. the shape of the curve doesn't change) causes a narrow range of results for the total basin. By allowing the most likely value to wander for a single section (superimposing a distribution on top of another distribution and allowing the shape of the curve to change), the range of results can be widened into something far more reasonable. It also makes sense for a largely undeveloped basin: we don't know what undrilled areas look like and so whole areas could range from low to high.

For a mapped variable, this can be thought of as forcing a map into more pessimistic and optimistic versions.



For example, net-to-gross ratio.

Three things were used to determine net pay from well logs:

1- Gamma-ray needed to be high (>100 api)

2- Bulk density needed to be on the low side (<2600 kg/m3)

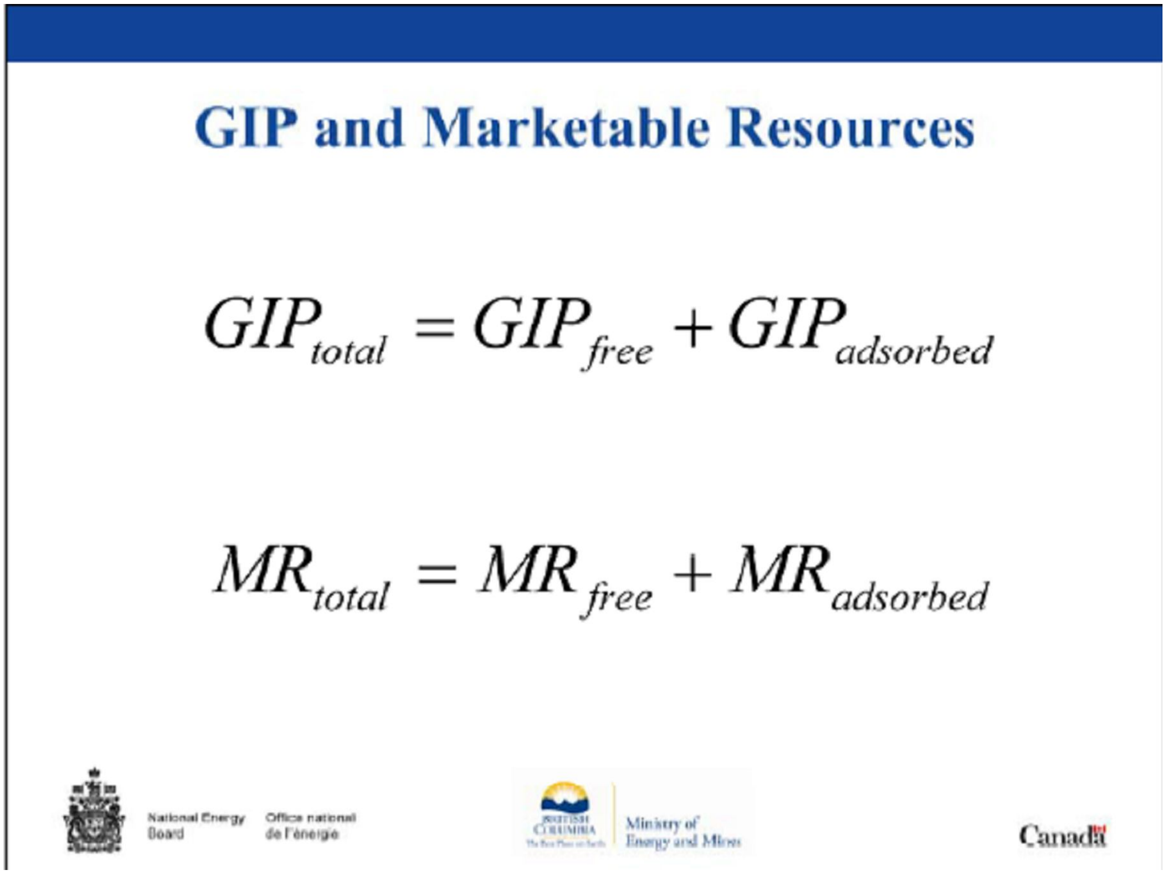
3- Resistivity (>10 ohms)

If those three conditions were met then the section was considered to have pay.

Net-to-gross ratios were then mapped.

Sections where well data existed were held static. For the sections where the well data didn't exist, the grid point became the most likely value in a distribution.

The well on the left, for example, is in the north and has a high net to gross ratio and the well on the right is in the south of the basin, characterized by limey mudstones with very little pay and has a low net to gross ratio. The sections in which each of these wells exist would use the "real" net to gross ratio. The sections around them would use a distribution with a most likely value that depended on the mapping. And, with the distribution of distributions, that most likely value around them could be forced higher or lower on each iteration as the entire map shifted from lower to higher.



It is shale gas so there are two components to the gas in place and marketable resources: free gas and adsorbed gas.

Marketable resources definition: gas in place (GIP) that can be developed in current marketable conditions (acknowledging that some things like costs are still decreasing). At current prices, much of the Horn River Basin resource would remain undeveloped. We're just trying to estimate what will likely be developed in the long term.

Free Gas

$$GIP_{free} = A \times H \times NtG \times \Phi \times (1 - S_w) \times \left(\frac{D \times PG \times T_S}{P_S \times T_F \times Z} \right)$$

$$MR_{free} = GIP_{free} \times (1 - SL) \times RF$$

Geological Maps:
Gross Shale Thickness (*H*)
Net to Gross Ratio (*NtG*)
Depth (*D*)
Pressure Gradient (*PG*)

Tied to Depth Map:
Compressibility (*Z*)
Formation Temperature (T_F)
Surface Loss (*SL*)

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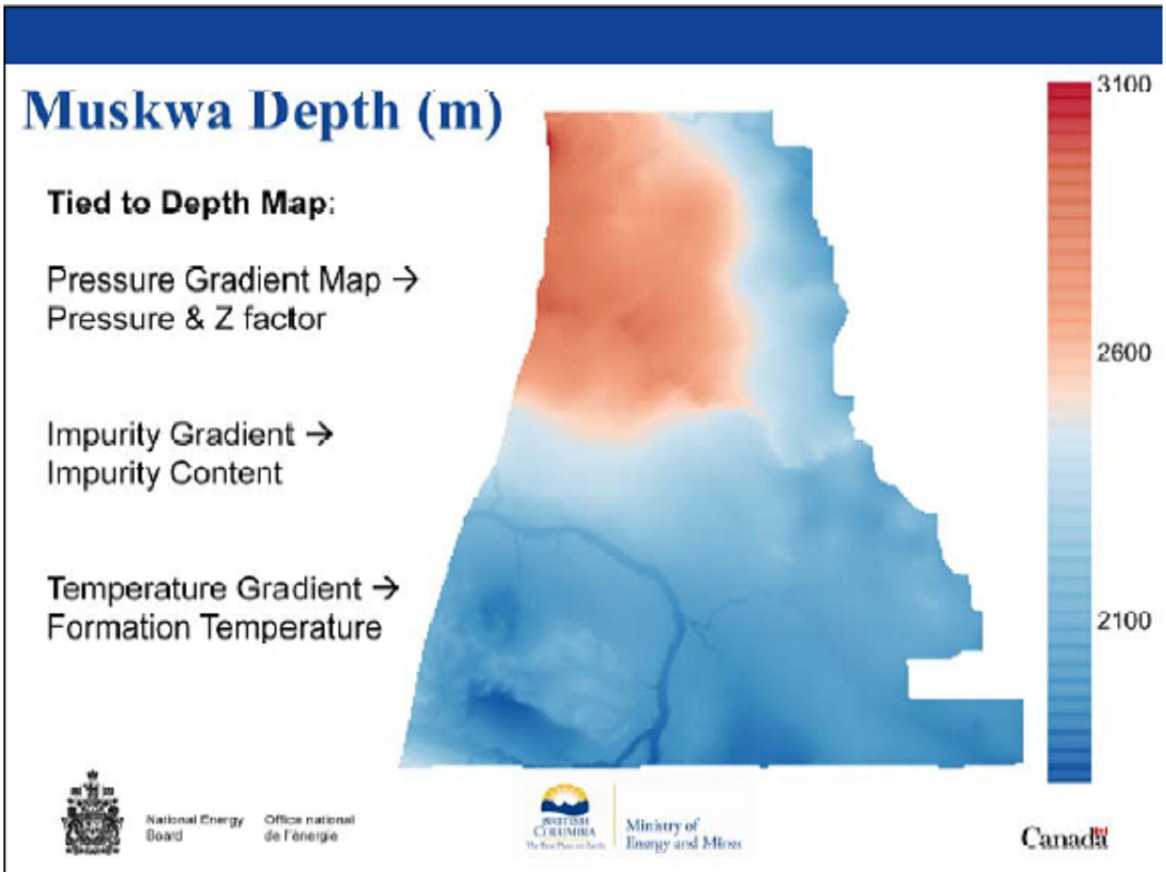
Free gas in place for each tract is calculated as a standard volumetric equation. Marketable Resources are the recoverable portions of Gas in Place (GIP times a recovery factor), minus surface losses through gas impurities and fuel gas.

Red triangles indicate where a distribution was used in the Monte Carlo simulation.

Importantly, not every variable in the equation was mapped because of data constraints (we didn't have confidence in our abilities to map them accurately).

The maps that were used were gross shale thickness, net-pay-to-gross-pay ratio, depth, and pressure gradient. Of these, the grid points were static (no distribution) for thickness and depth (since they're pretty well known), but made variable for the net-to-gross ratio and pressure gradient, largely because there's far more uncertainty about them.

In the volumetric equation, formation pressure is a function of Depth times the Pressure Gradient (to model how pressures vary across the basin with depth). And, while the depth map may be static, it is there to model how some variables in the equations change across the basin, like compressibility, formation temperature, and surface loss, because the gas impurity contents change across the basin with formation depth.

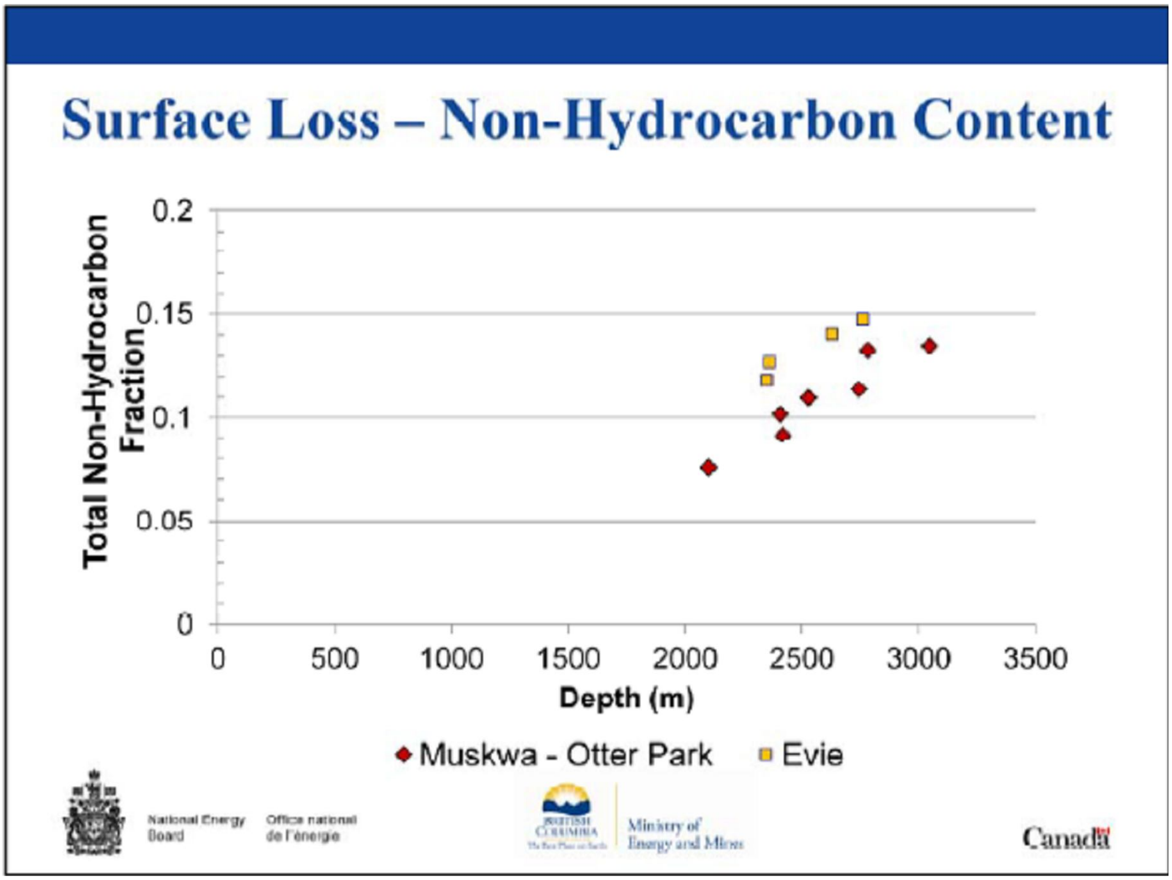


The depth maps (derived from subsea depths of the formations and a digital terrain model – you can see some of the surface effects on this map, like the Snake River in the southwest corner) was one of the more important factors in the estimate of resources in the Horn River Basin as it changed significantly from one side of the basin to the other.

-Pressure (distribution was applied through the pressure gradient map, which was allowed to vary like the net-to-gross map)

-Impurity contents (a straight distribution was applied – more on next slide)

-Temperature (no distribution used)



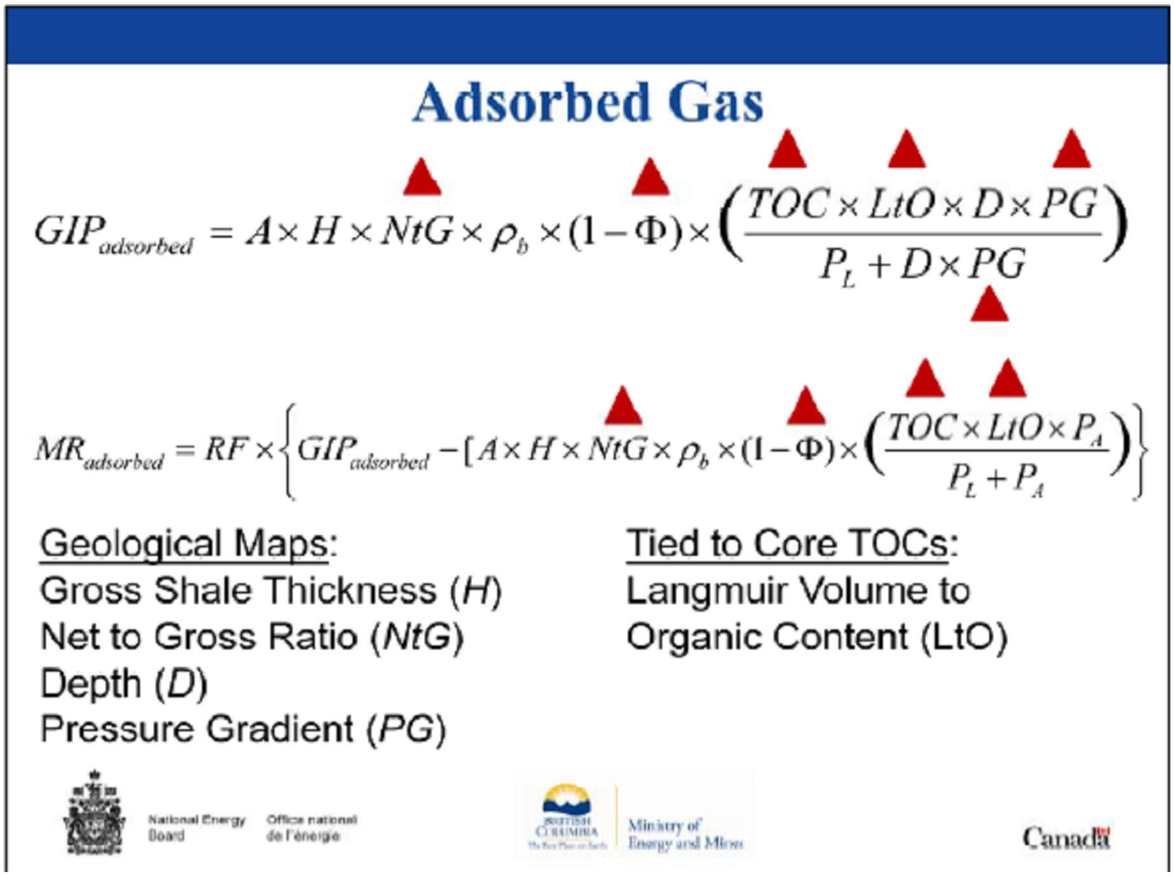
The Horn River Basin is well known for its abnormally high gas impurities, mostly carbon dioxide. By plotting the non-hydrocarbon gas contents versus depth, it was determined that non-hydrocarbon gas impurities increased with depth in a relatively predictable manner. Thus, we could better estimate surface losses by tying them to the depth map for each grid point.

A distribution was added to reflect that the data do not fall on a straight line.

To estimate surface losses, we not only removed the simulated non-hydrocarbon content, but also fuel gas for transmission (3%) and the non-hydrocarbon content was multiplied by 1.5 to estimate how much total gas would be lost, not only from impurities and but for fuel gas for processing. Of course, this could change if the Fort Nelson area and northward is hooked to the BC Hydro grid and hydroelectric power becomes available for gas-processing plants and pipeline facilities, which would reduce usage of fuel gas.

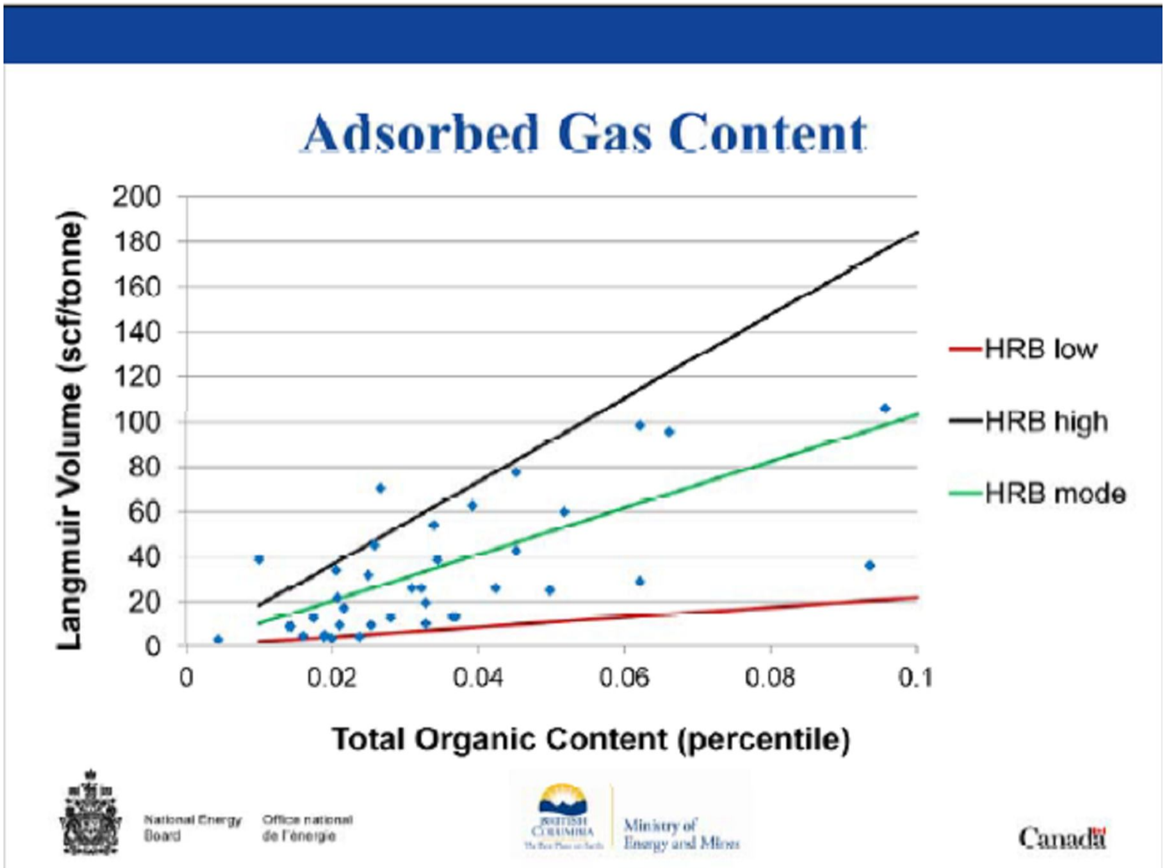
Importantly, the Evie Shale appears to have a higher acid-gas content than the Muskwa and Otter Park samples. This, of course, is relevant to estimating marketable volumes.

Note: some samples were excluded because of anomalously high values, which likely originated from completion techniques and early flowback. Some samples were excluded because of what appeared to be commingling between the Muskwa-Otter Park production and Evie production



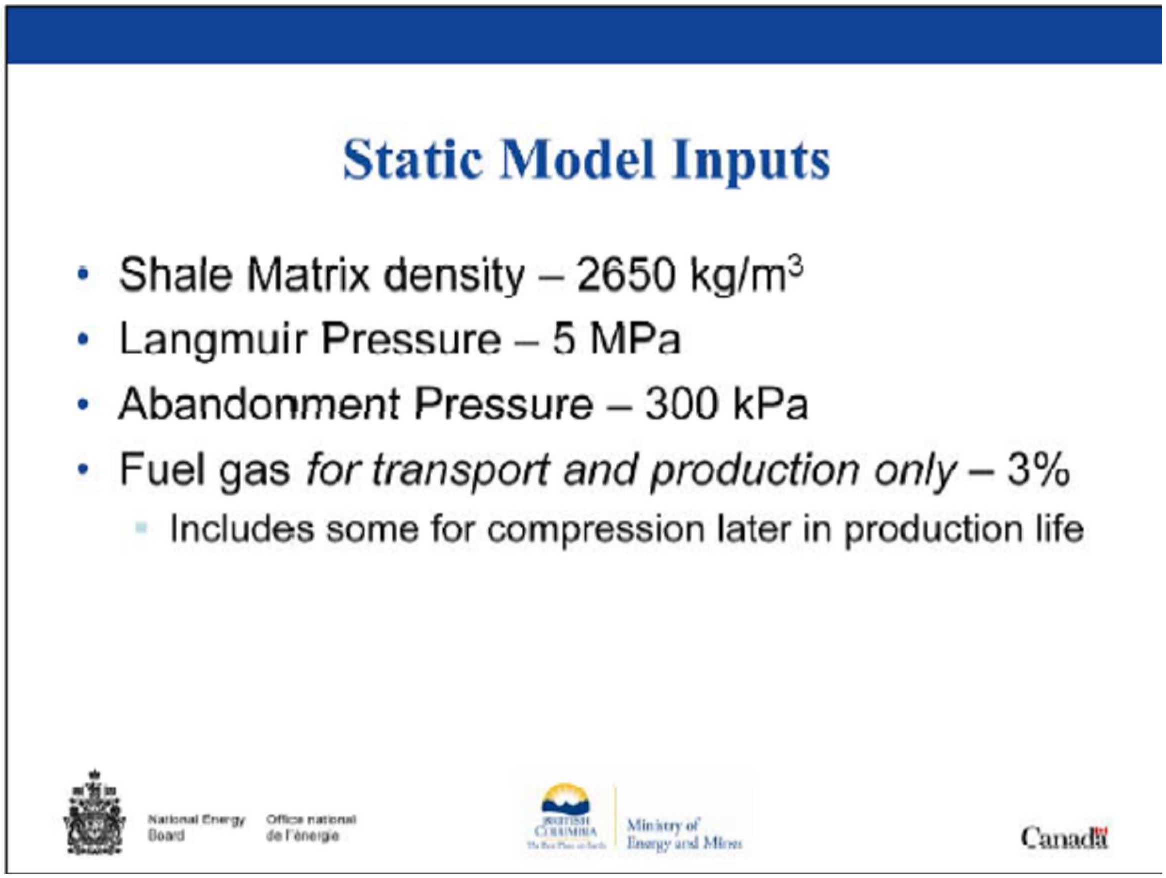
Adsorbed GIP is a standard adsorbed-gas equation, where reservoir pressure is Depth times the Pressure Gradient. The Langmuir Volume is the TOC multiplied by a Langmuir Volume to Organic Content ratio, as determined by a spread of data from core.

Marketable Resources are more complicated, with the adsorbed GIP minus adsorbed gas at abandonment pressure, and multiplied by a recovery factor to determine how much of that desorbed gas could actually get out of the formation. We used the same recovery factor as for the free gas content though the recovery factors could content, be different in reality. We didn't have enough data to determine how different.



In order to estimate adsorbed-gas contents, the Langmuir volume was plotted against Total Organic Content.

This way, typical organic contents in the shales could be estimated and the amount of gas that could adsorb to them estimated.



Some things in the equation were constant.

We also included a fuel gas component to marketable gas to estimate how much would be left after gas transport for consumption in markets. The fuel gas includes some compression that would be needed later on in the life of the wells.

Results – Expected Volumes

	Discovered (Tcf)	Undiscovered (Tcf)	Total (Tcf)
Free GIP	12	335	348
Adsorbed GIP	3	96	100
Total GIP	15	433	448
Free Marketable	2	58	60
Adsorbed Marketable	1	16	18
Total Marketable	3	75	78

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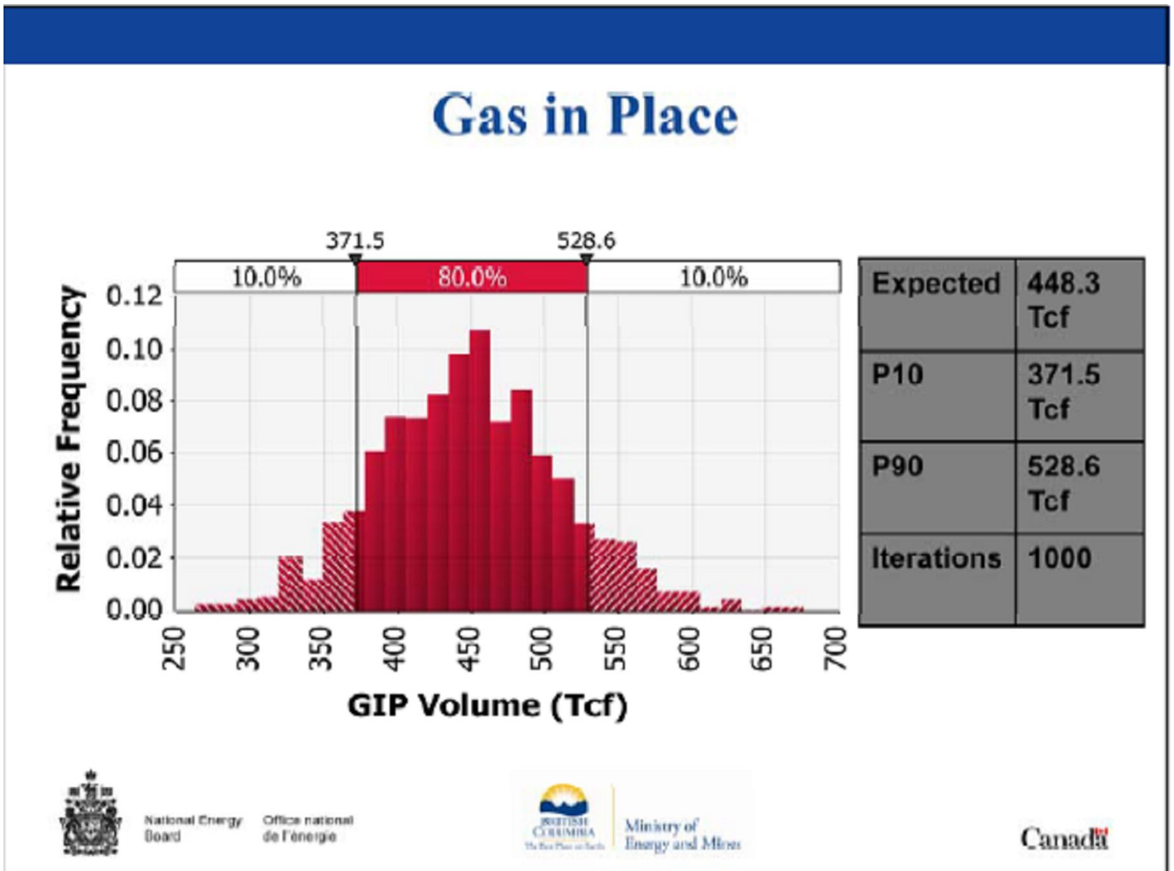
A few takeaways:

Because of rounding these numbers might not add up correctly.

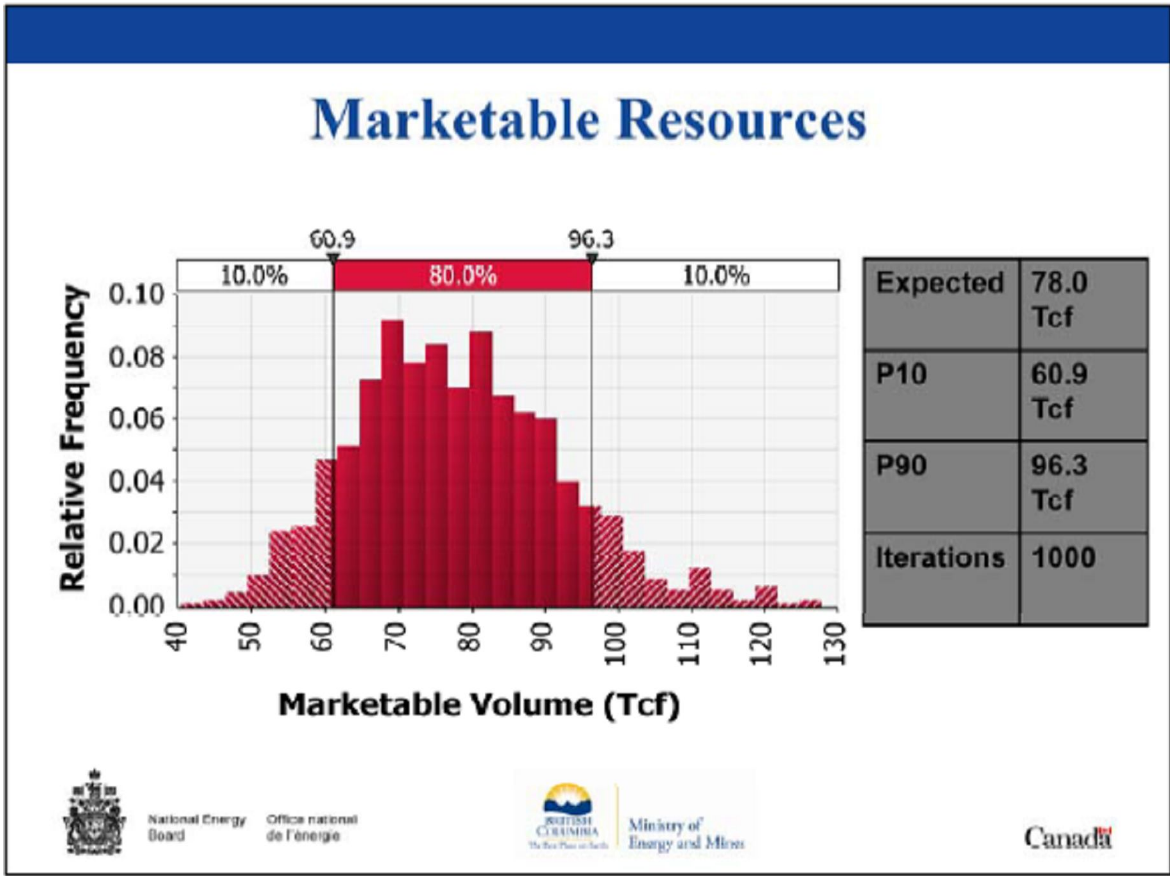
The amount of discovered gas is very low compared to the undiscovered portion. This is because discoveries are based on the presence of a well (horizontals included) and most of the basin remains undrilled. While land holdings are extensive, they're not considered discovered according to our methodology. This disposition of gas between undiscovered and discovered resources is in contrast to most studies of conventional resources, where the vast bulk is discovered, simply because the WCSB has been very well drilled.

The adsorbed gas component of GIP and marketable resources in the Horn River Basin is 22%. This is significantly higher than previously published estimates, where adsorbed gas was expected to be very small. This is probably because the basin is now known to be significantly overpressured, which increases the amount of gas that can adsorb, and there has been significantly more core sampling and testing to determine Langmuir Volumes and the reservoir is known better.

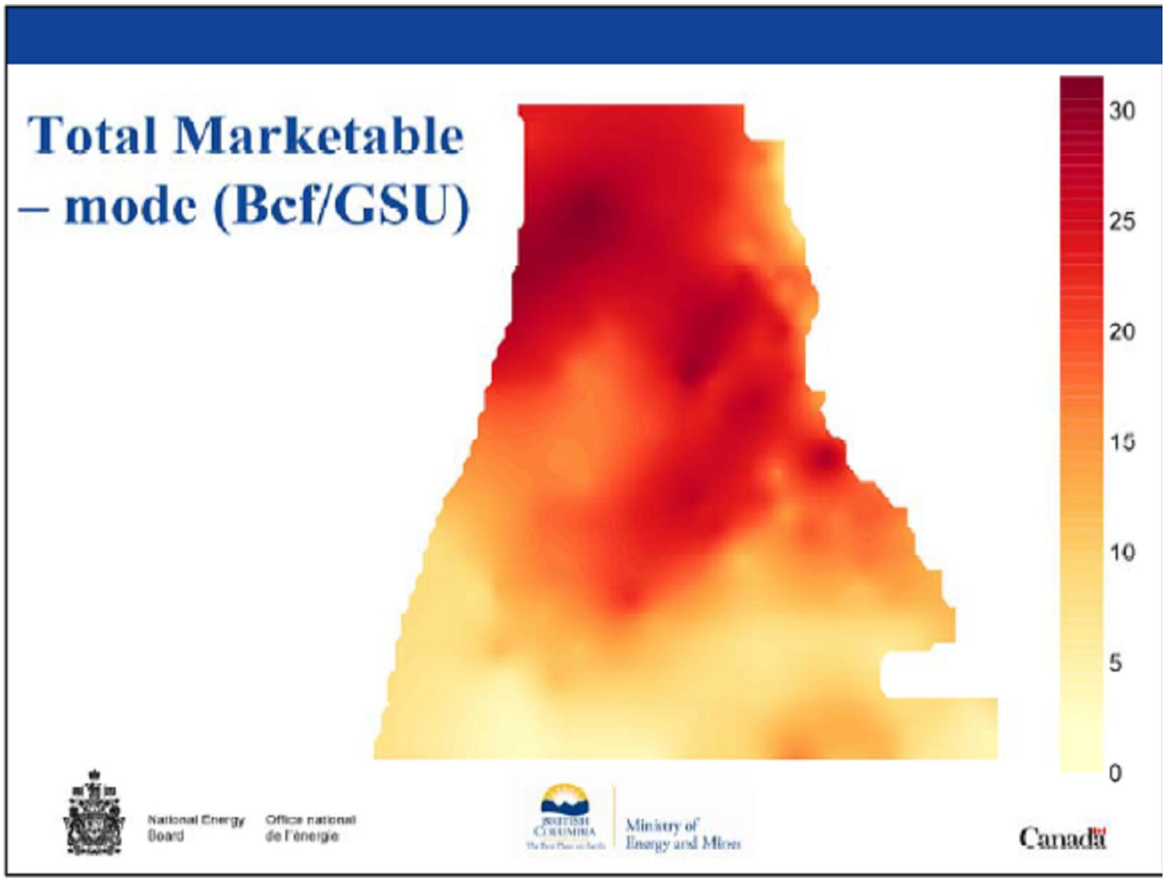
It must be noted that marketable adsorbed resources could be lower than noted here based of how well the gas desorbs even with lower pressures. At the current time, there was not enough public information with which to make an estimate.



Total GIP appears to be similar to other published estimates, though maybe a bit on the lower side. While our high and low estimates are 372 Tcf and 529 Tcf, they're based on P10 to P90 values. Overall, the spread here indicates anywhere from 275 Tcf to 600+ Tcf, though those end members are very improbable.

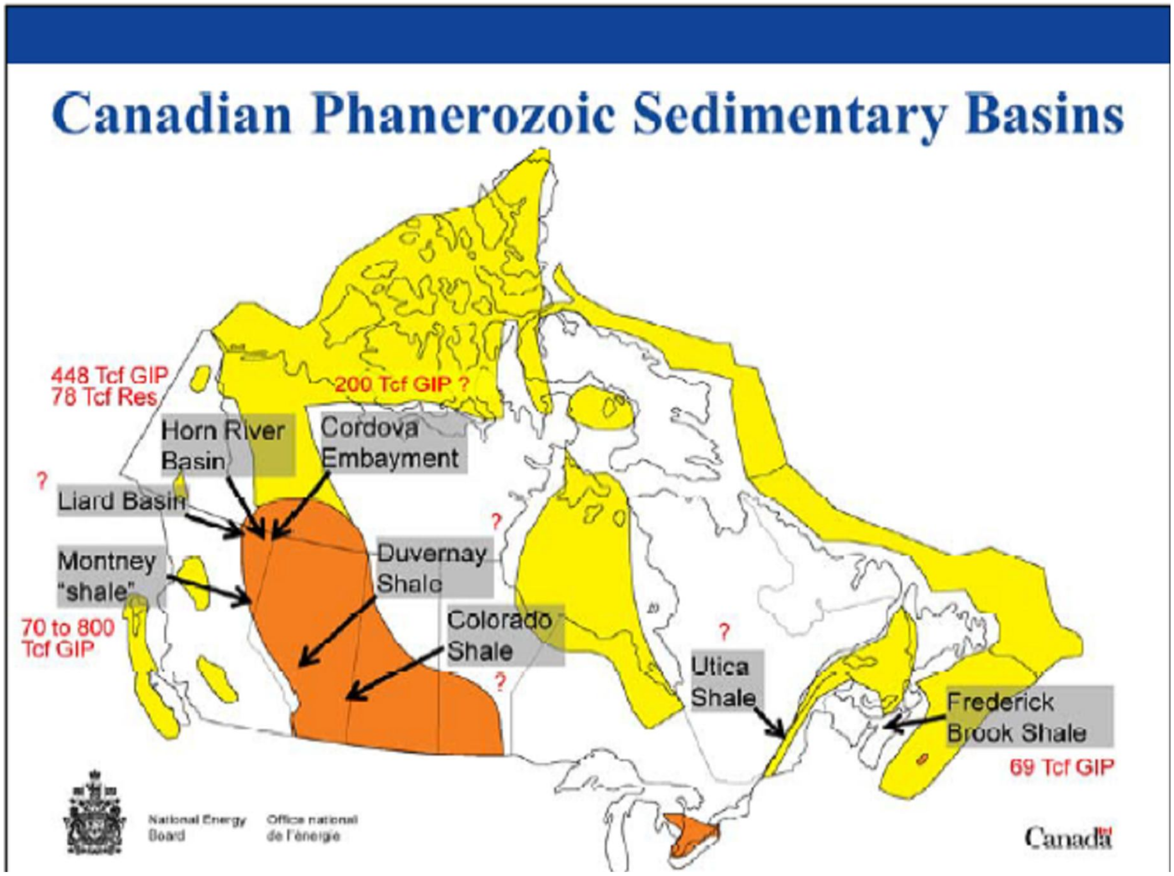


The marketable numbers here includes gas subtracted from areas considered unlikely to be developed. Again, while we use P10 and P90 values for our upper and lower reported boundaries, the spread here is from 45 to 125 Tcf. This estimate could be revised significantly as more data becomes available and recoveries are better understood. In particular, while some companies are reporting recoveries of over 30%, we used lower values, between 20 and 25%, largely because we are considering more than core areas and development of non-core areas could push recovery factors downward.

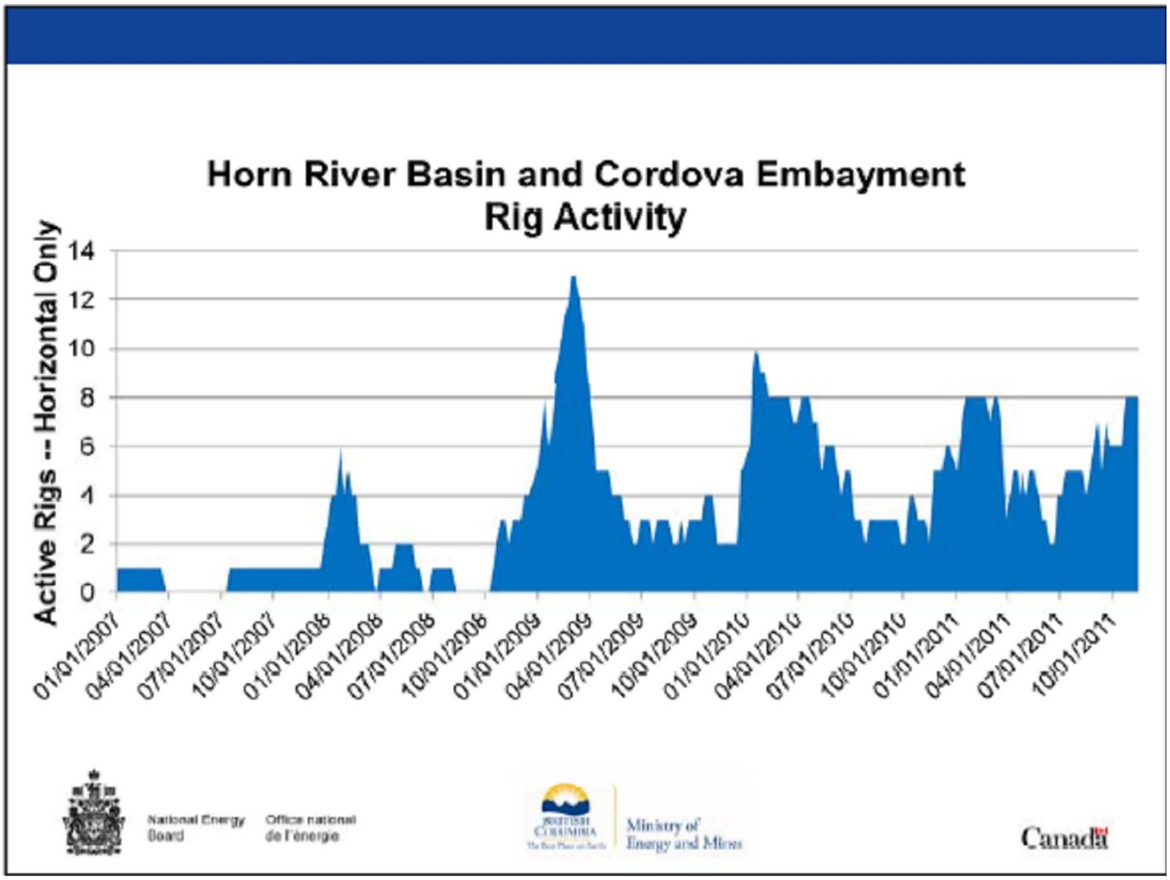


Results may also be mapped

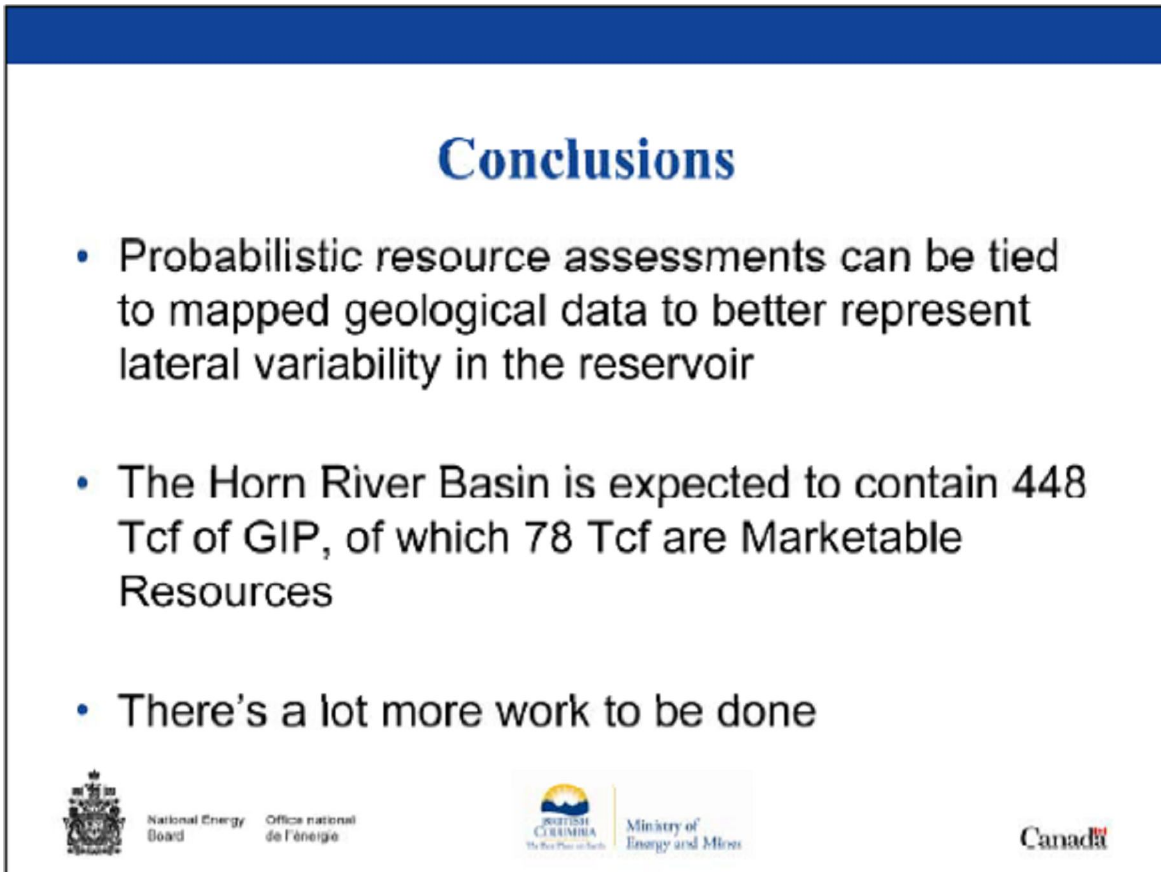
Here is the mode of the TOTAL MARKETABLE summed for the shales. This is not statistically correct but it gives some indication of where the resource is concentrated in the Basin.



Map of Canada with the distribution of Phanerozoic sedimentary basins (yellow). The map also locates some of the active shale gas development (Horn River and Montney) as well as some prospective shales currently being at different stages of evaluation.



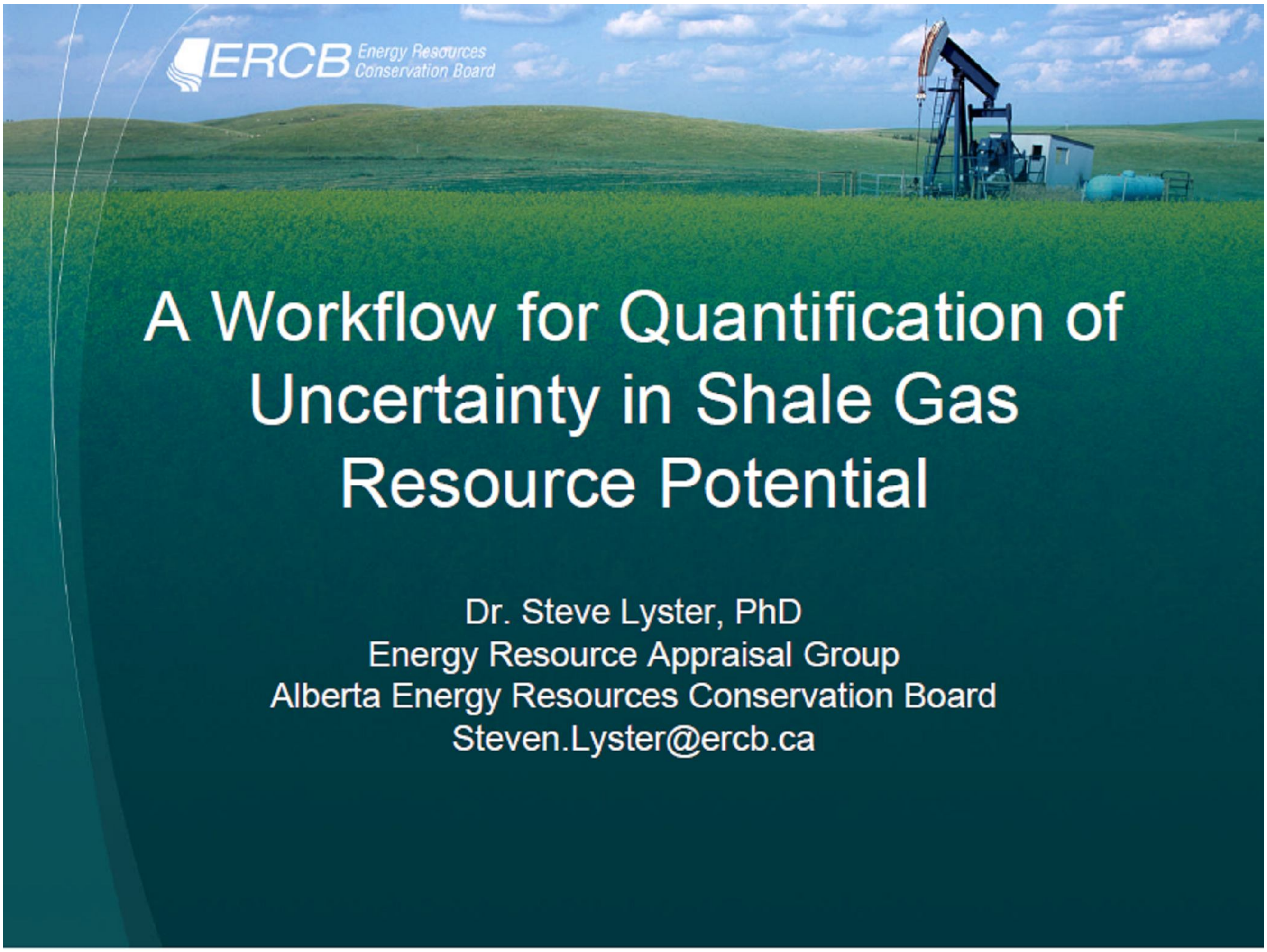
Active rigs in the Horn River Basin and Cordova Embayment. Form a slow start in early 2007, the pace of drilling has significantly increased over the last 4 years.



Future work would include increasing the types of maps used in the assessment to include TOCs and, if possible, porosity and water saturation, because, like the other mapped variables, the parameters almost certainly vary from area to area.

Study is available online from the websites of both the NEB and B.C. MEM

Appendix C: Presentation by Steve Lyster of Alberta ERCB



Outline

- Data Used for Shale Gas Potential
- Mapping Primary Variables
- Determining Conditional Variables
- Fluid Distributions
- Calculating Resources
- Joint Uncertainty / Simulation
- Comments and Discussion

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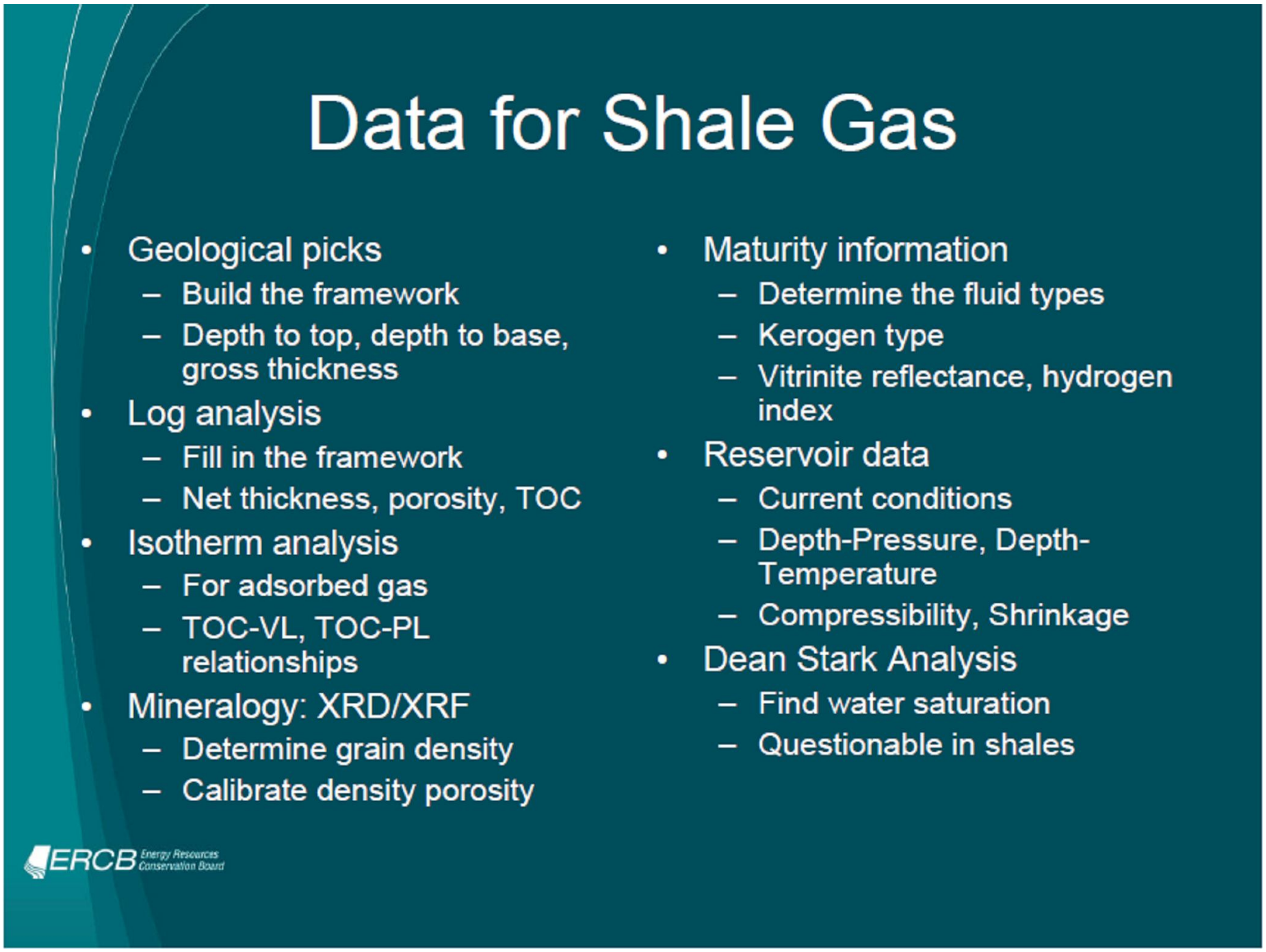
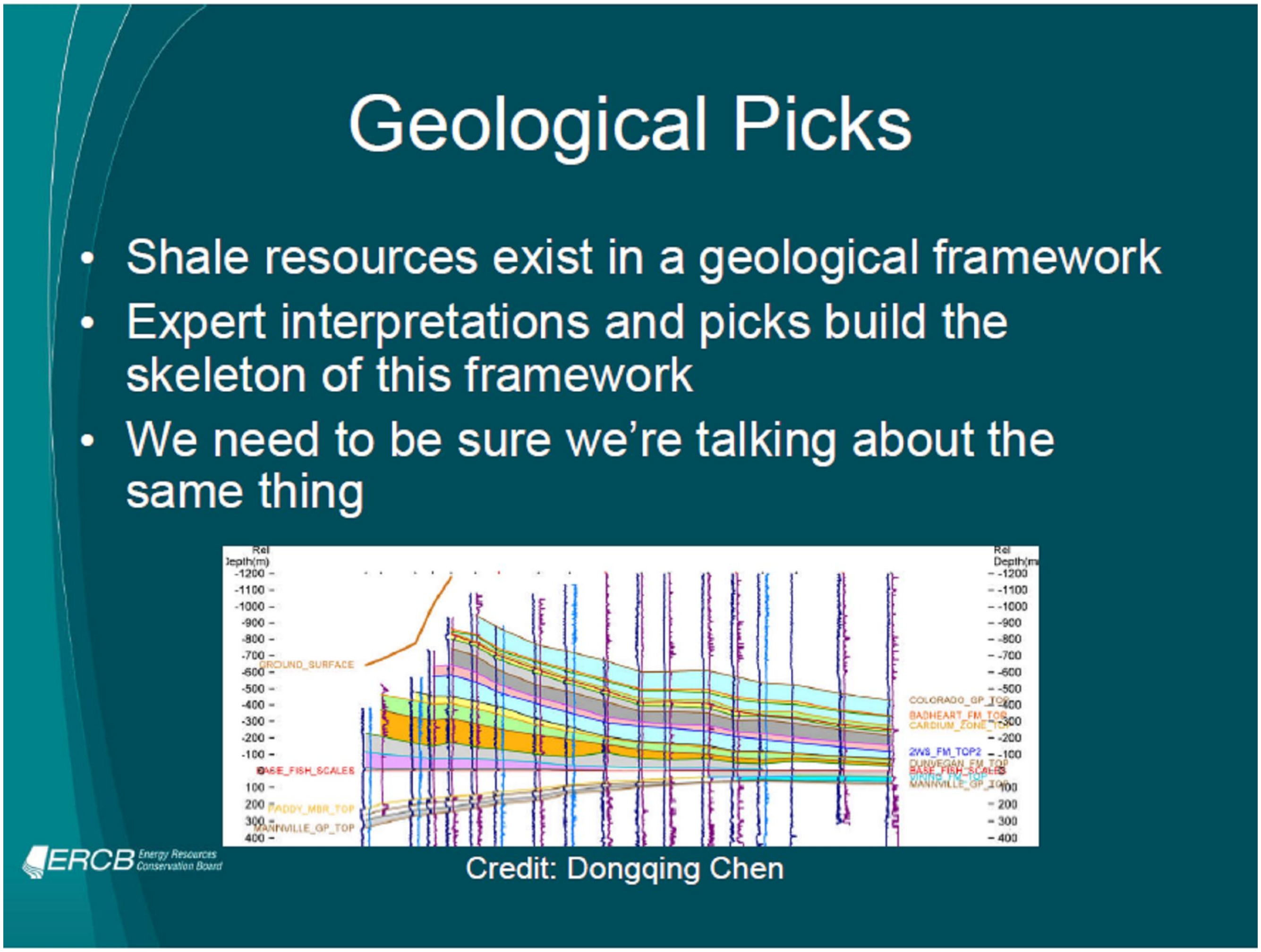
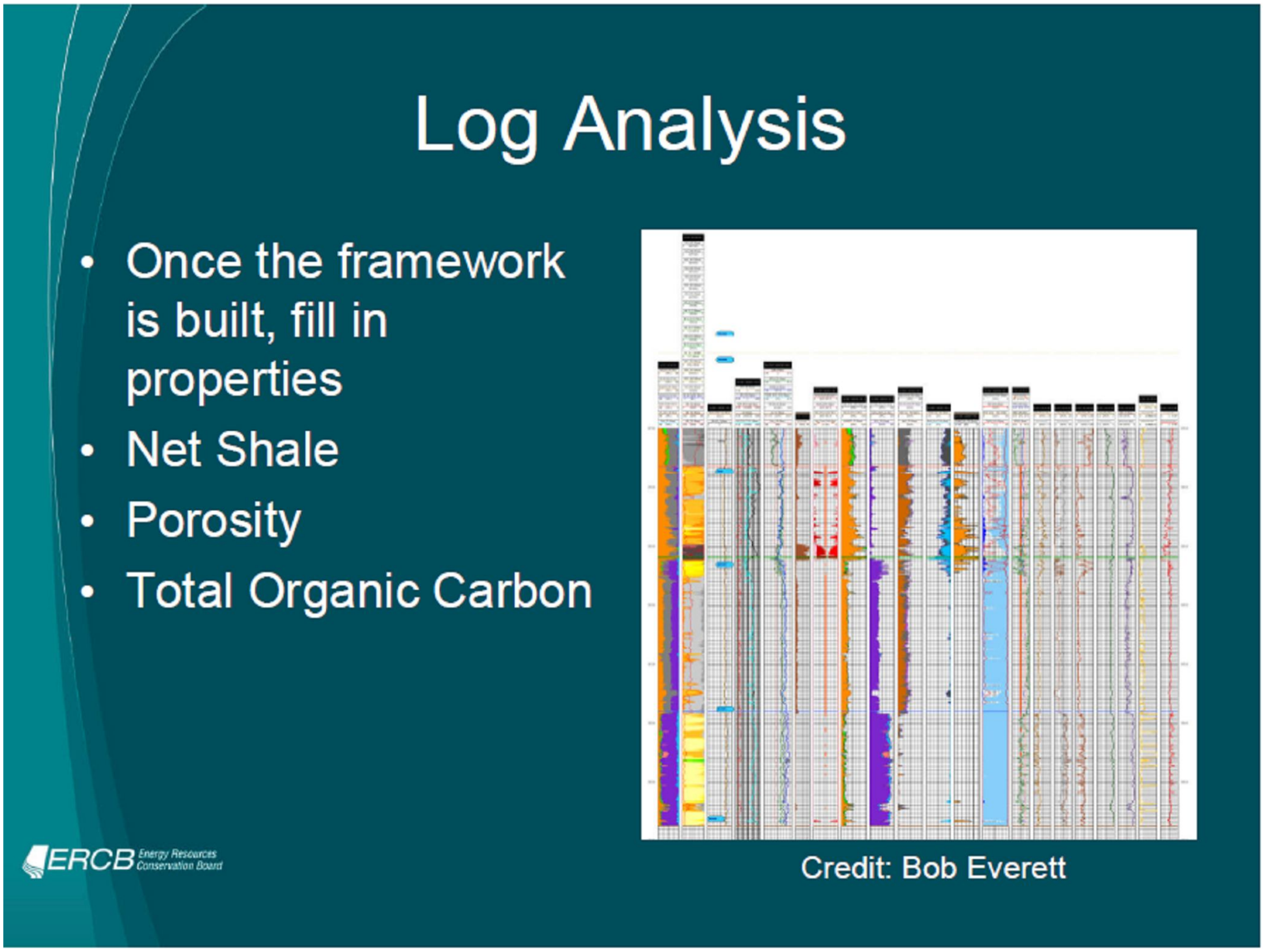


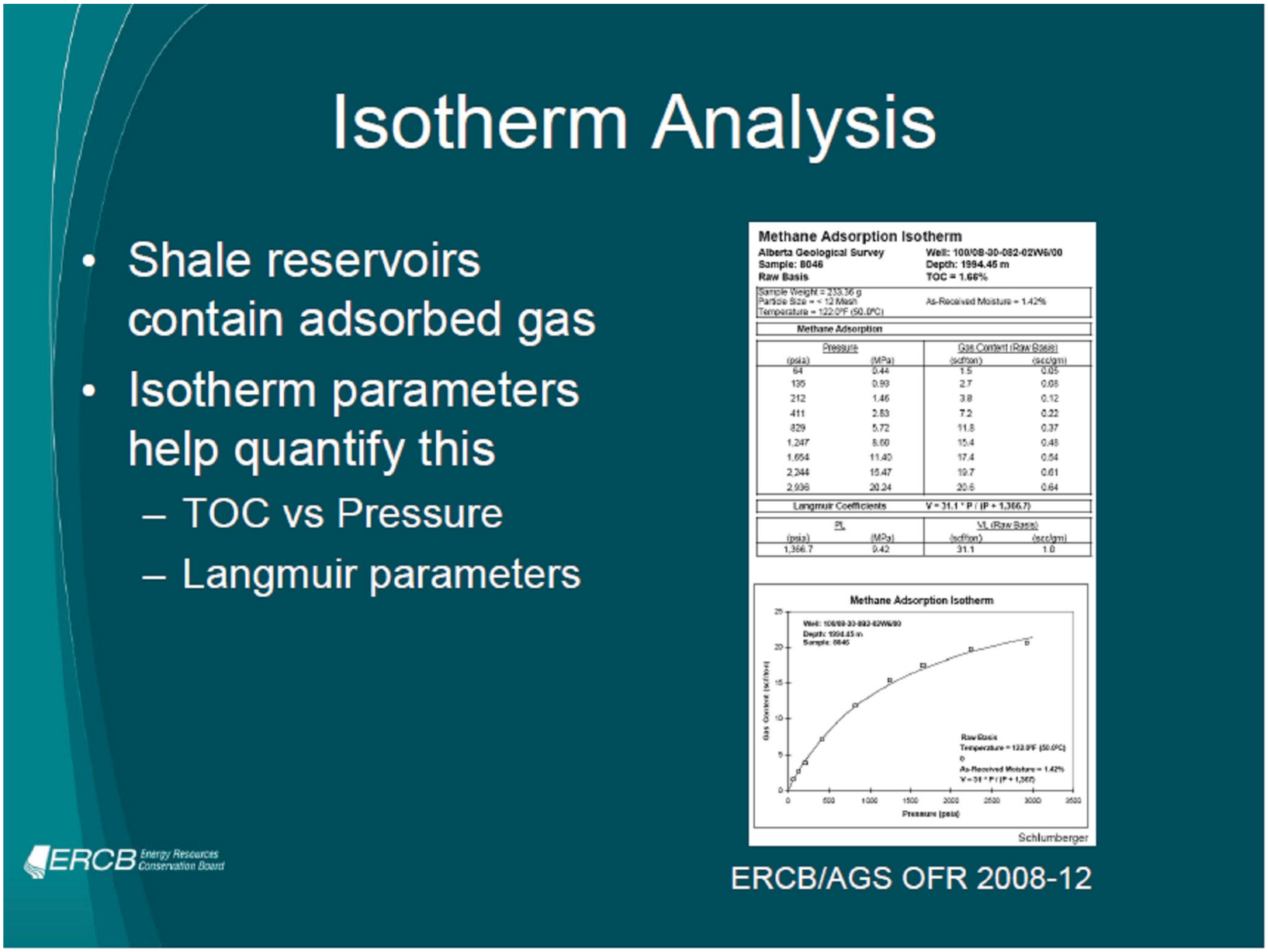
In order to generate a sound resource evaluation, a large number of geological data types are needed. The more data that is available, the better the resource estimates will be and the better the quantification of the uncertainty.



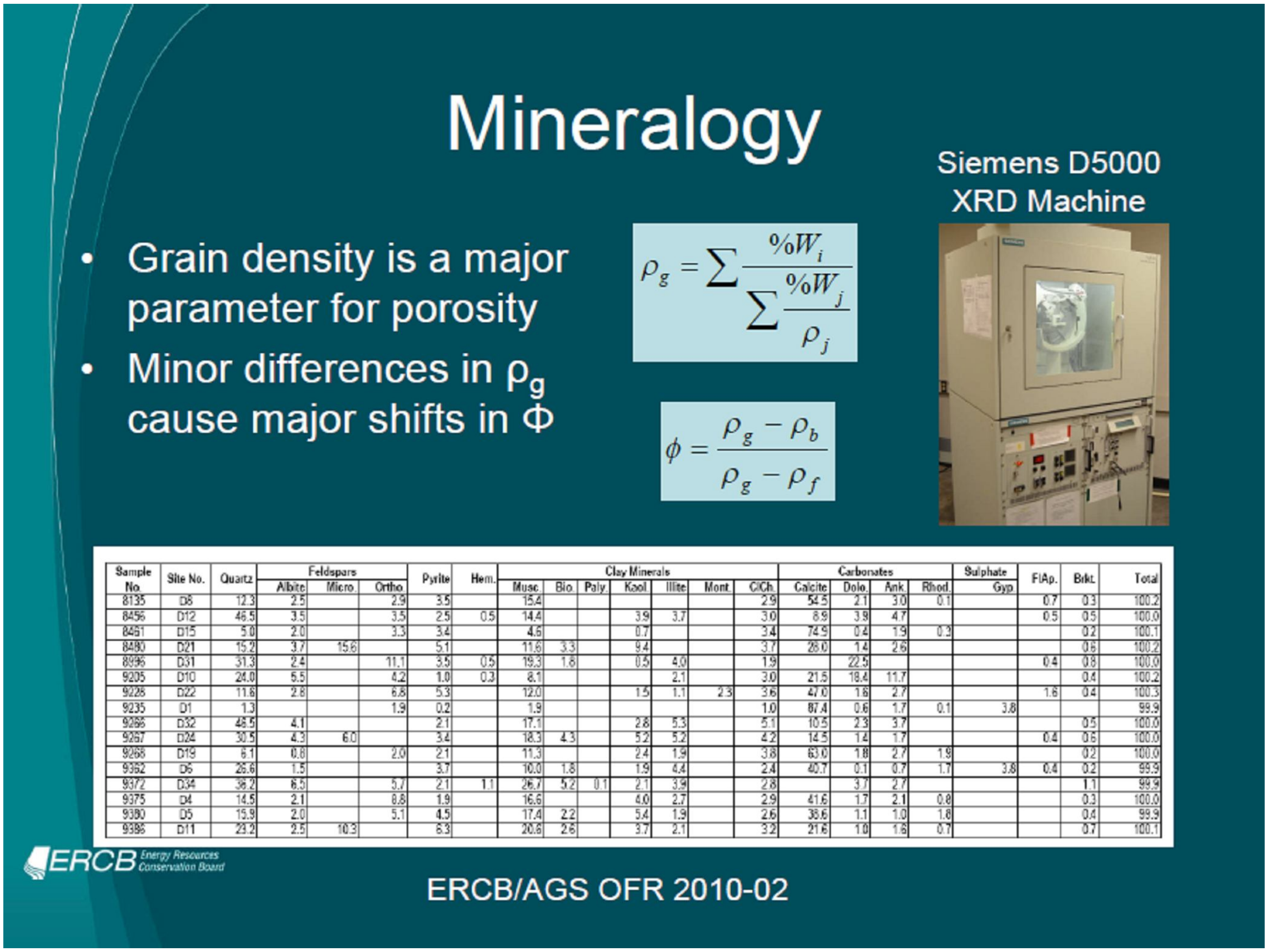
Geological picks contribute to the building of the geological framework and the determination of basic parameters such as depths to top, depths to base, widths, and gross thickness of pay zones. Over large areas such as those covered by many shales, problems may arise in ensuring consistent naming of formations and methodologies used for geological interpretation.



Log analysis provides fundamental information on net thickness, porosity, and total organic carbon (TOC), among other attributes. Modern logs are preferred, but even pre-1986 logs are to be evaluated with the caveat that they must be carefully checked for quality. This step fills in the geological framework with physical properties and defines the storage capacity of the shale. All log analyses must be calibrated to sample data.

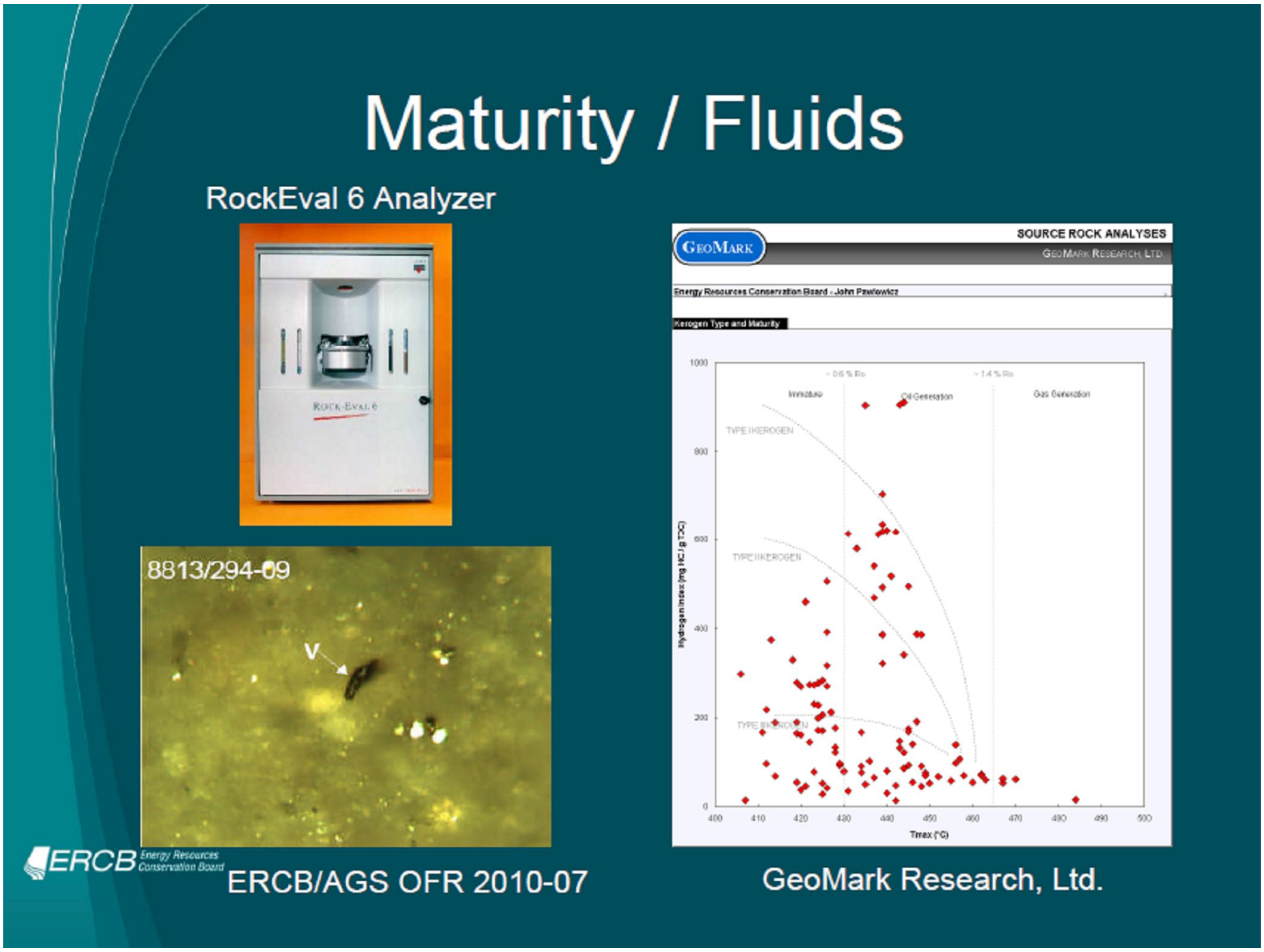


Isotherm analysis can help quantify the amount of adsorbed gas contained in shale reservoirs. Isotherm analysis examines TOC versus pressure, as well as Langmuir parameters in the shale reservoir, setting out TOC-VL (Langmuir volume) and TOC-PL (Langmuir pressure) relationships.

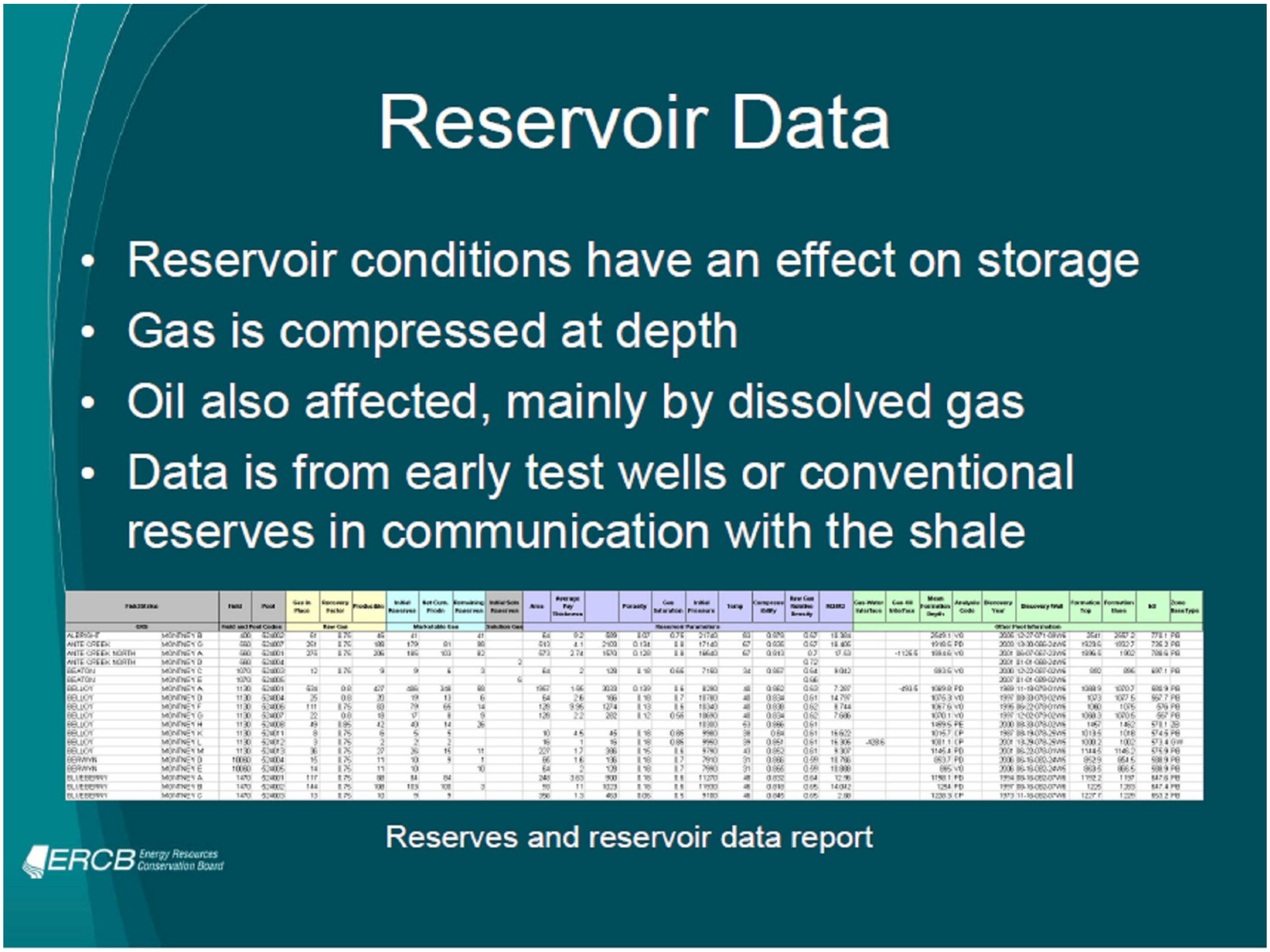


Sample No.	Site No.	Quartz	Feldspars			Pyrite	Hem.	Clay Minerals							Carbonates				Sulphate	FlAp.	Brkt.	Total
			Albite	Micro.	Ortho.			Musc.	Bio.	Paly.	Kaol.	Illite	Mont.	ClCh.	Calcite	Dolo.	Ank.	Rhod.	Gyp.			
8135	D8	12.3	2.5		2.9	3.5		15.4						2.9	54.5	2.1	3.0	0.1		0.7	0.3	100.2
8456	D12	46.5	3.5		3.5	2.5	0.5	14.4			3.9	3.7		3.0	8.9	3.9	4.7			0.5	0.5	100.0
8461	D15	5.0	2.0		3.3	3.4		4.6			0.7			3.4	74.9	0.4	1.9	0.3			0.2	100.1
8480	D21	15.2	3.7	15.6		5.1		11.6	3.3		9.4			3.7	28.0	1.4	2.6				0.6	100.2
8996	D31	31.3	2.4		11.1	3.5	0.5	19.3	1.8		0.5	4.0		1.9		22.5				0.4	0.8	100.0
9205	D10	24.0	5.5		4.2	1.0	0.3	8.1				2.1		3.0	21.5	18.4	11.7				0.4	100.2
9228	D22	11.6	2.8		6.8	5.3		12.0			1.5	1.1	2.3	3.6	47.0	1.6	2.7			1.6	0.4	100.3
9235	D1	1.3			1.9	0.2		1.9						1.0	87.4	0.6	1.7	0.1	3.8			99.9
9266	D32	46.5	4.1			2.1		17.1			2.8	5.3		5.1	10.5	2.3	3.7				0.5	100.0
9267	D24	30.5	4.3	6.0		3.4		18.3	4.3		5.2	5.2		4.2	14.5	1.4	1.7			0.4	0.6	100.0
9268	D19	6.1	0.8		2.0	2.1		11.3			2.4	1.9		3.8	63.0	1.8	2.7	1.9			0.2	100.0
9362	D6	26.6	1.5			3.7		10.0	1.8		1.9	4.4		2.4	40.7	0.1	0.7	1.7	3.8	0.4	0.2	99.9
9372	D34	36.2	6.5		5.7	2.1	1.1	26.7	5.2	0.1	2.1	3.9		2.8		3.7	2.7				1.1	99.9
9375	D4	14.5	2.1		8.8	1.9		16.6			4.0	2.7		2.9	41.6	1.7	2.1	0.8			0.3	100.0
9380	D5	15.9	2.0		5.1	4.5		17.4	2.2		5.4	1.9		2.6	38.6	1.1	1.0	1.8			0.4	99.9
9386	D11	23.2	2.5	10.3		6.3		20.6	2.6		3.7	2.1		3.2	21.6	1.0	1.6	0.7			0.7	100.1

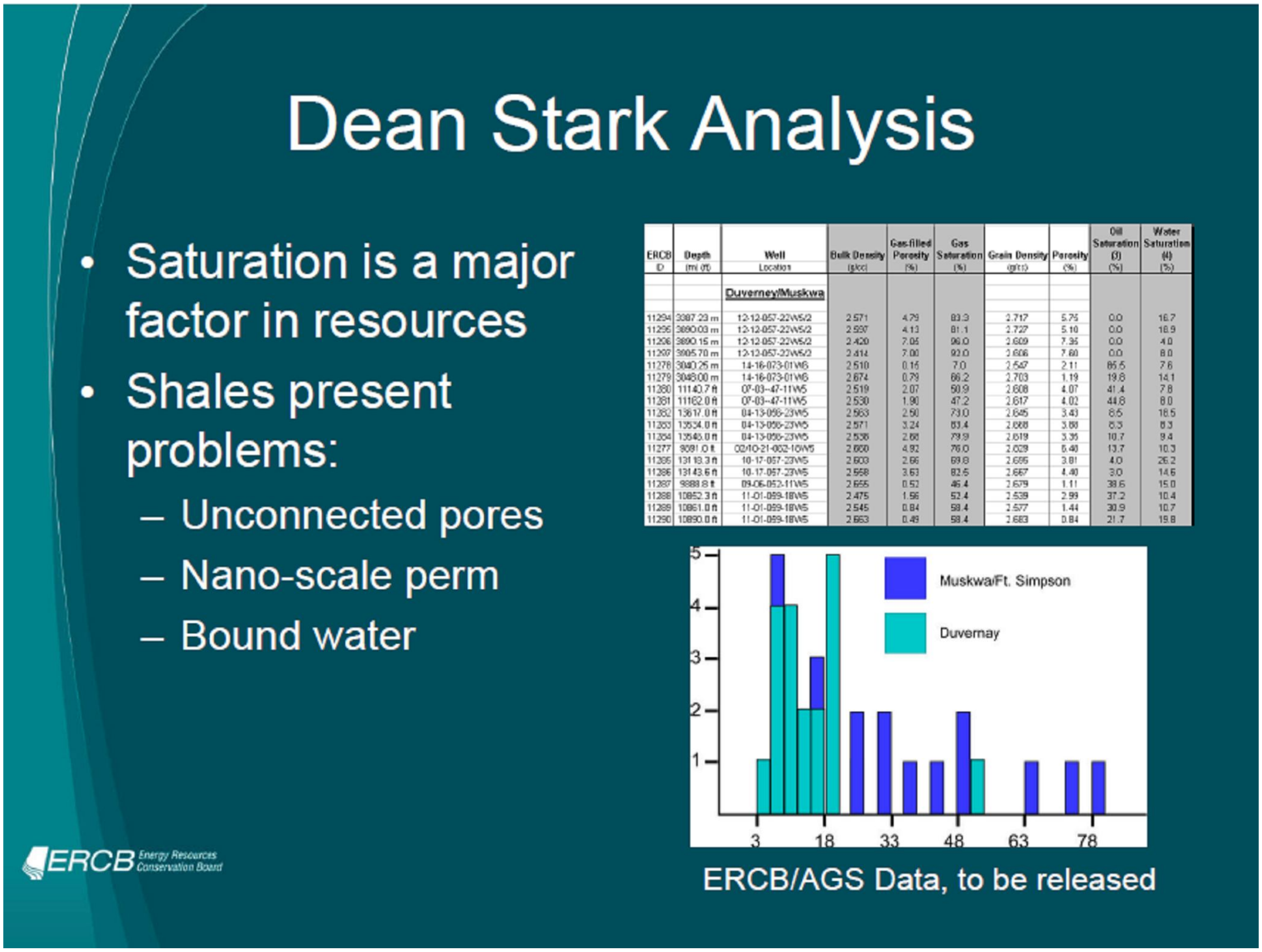
Mineralogy is important because minor differences in grain density cause major shifts in porosity. The mineralogy of shale also provides important information on its capacity to fracture. Various techniques will provide mineralogical information both on quantitative and semi-quantitative grounds.



Maturity data provide information on fluid types, kerogen types, vitrinite reflectance, and hydrogen index (HI) across different sections. The understanding of the level of thermal maturation is a critical data for evaluating the type of hydrocarbon (oil, wet gas, dry gas) expected for specific areas. Many shale plays cover such large areas that they extend all the way from shallow, immature zones through oil, condensate, wet gas, and into overmature dry gas zones.

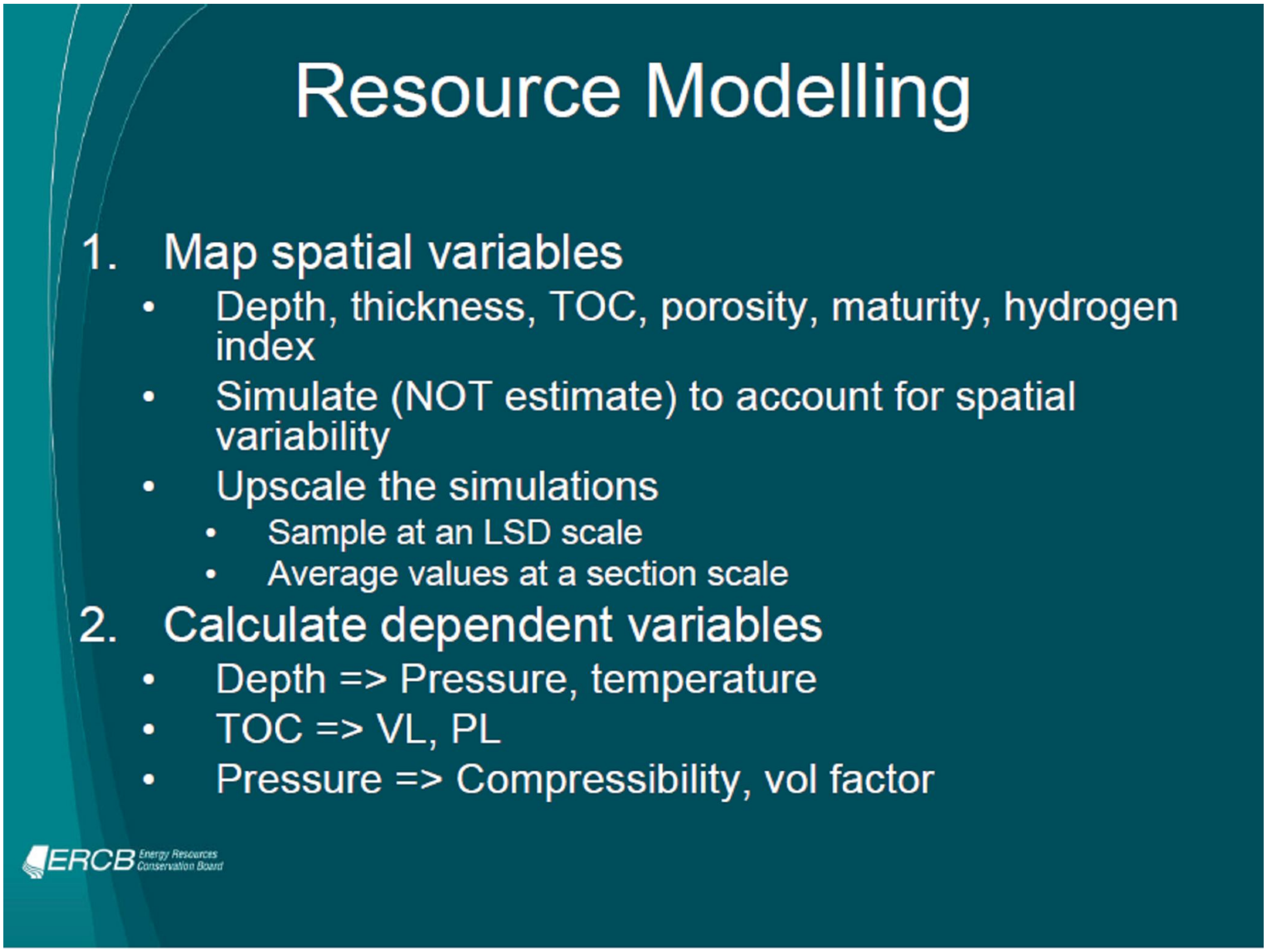


Reservoir conditions potentially represent a major source of uncertainty due to their effect on storage. In areas with minimal reservoir data for shale, data from test wells and from conventional reservoirs that are in communication with shale may be used. Analog or conventional reservoir data is not perfect, but in the early stages of shale resource assessment there is little else to go by. Reservoir data includes depth, pressure, temperature, compressibility, and shrinkage.

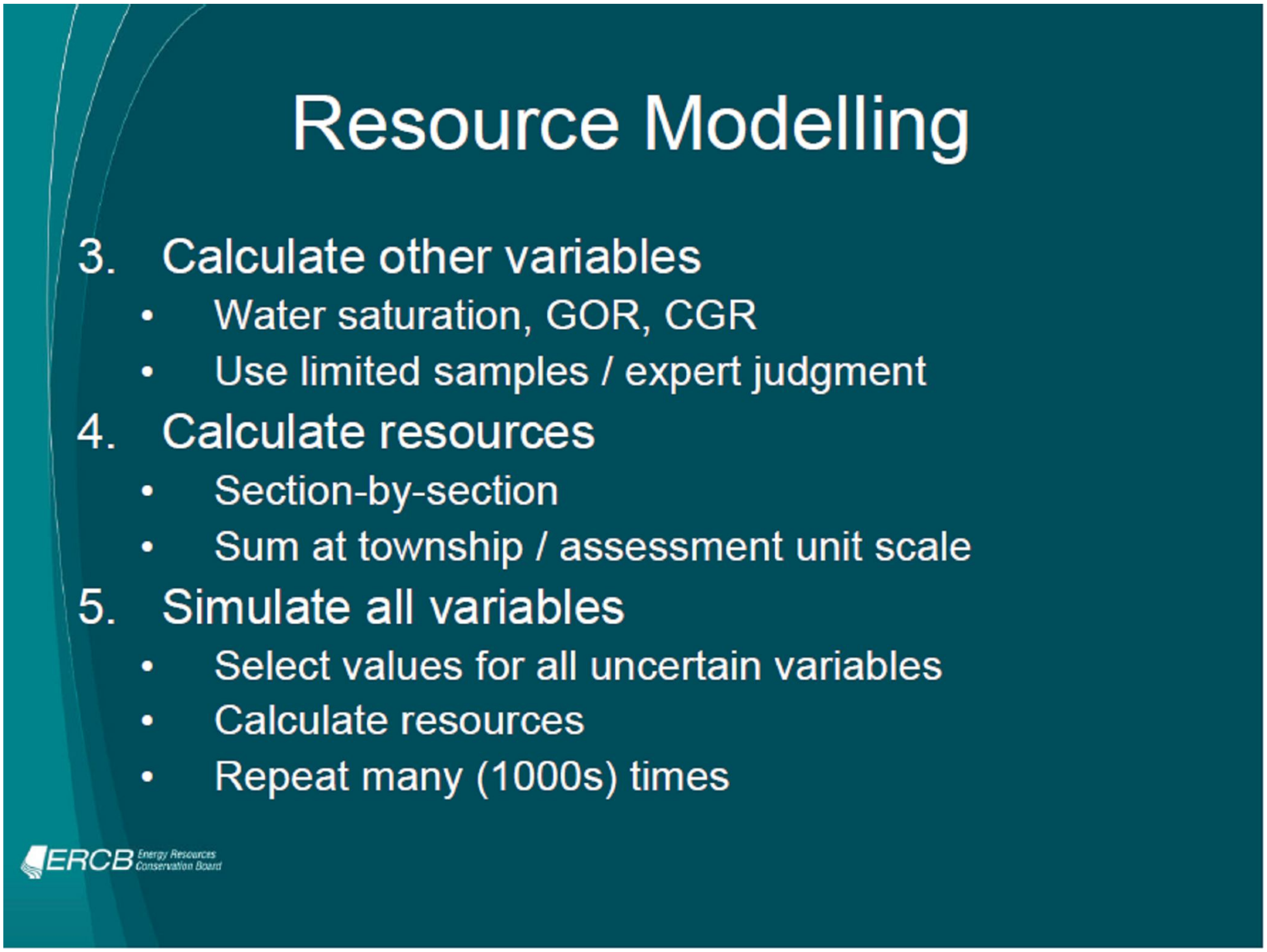


ERCB ID	Depth (m/ ft)	Well Location	Bulk Density (g/cc)	Gas-filled Porosity (%)	Gas Saturation (%)	Grain Density (g/cc)	Porosity (%)	Oil Saturation (3) (%)	Water Saturation (4) (%)
		Duverney/Muskwa							
11294	3887.23 m	12-12-057-22W5/2	2.571	4.79	83.3	2.717	5.75	0.0	16.7
11295	3890.03 m	12-12-057-22W5/2	2.597	4.13	81.1	2.727	5.10	0.0	18.9
11296	3890.15 m	12-12-057-22W5/2	2.420	7.05	96.0	2.609	7.36	0.0	4.0
11297	3905.70 m	12-12-057-22W5/2	2.414	7.00	92.0	2.606	7.60	0.0	8.0
11278	3040.25 m	14-16-073-01W6	2.510	0.16	7.0	2.547	2.11	85.5	7.6
11279	3048.00 m	14-16-073-01W6	2.674	0.79	66.2	2.703	1.19	19.8	14.1
11280	11140.7 ft	07-03--47-11W5	2.519	2.07	50.9	2.608	4.07	41.4	7.8
11281	11162.0 ft	07-03--47-11W5	2.530	1.90	47.2	2.617	4.02	44.8	8.0
11282	13617.0 ft	04-13-056-23W5	2.563	2.50	73.0	2.645	3.43	6.5	18.5
11283	13534.0 ft	04-13-056-23W5	2.571	3.24	83.4	2.668	3.88	6.3	8.3
11284	13546.0 ft	04-13-056-23W5	2.536	2.68	79.9	2.619	3.35	10.7	9.4
11277	9081.0 ft	02/10-21-002-10W5	2.600	4.92	76.0	2.629	6.40	13.7	10.3
11285	13118.3 ft	10-17-057-23W5	2.603	2.66	69.8	2.695	3.81	4.0	26.2
11286	13143.6 ft	10-17-057-23W5	2.558	3.63	82.5	2.667	4.40	3.0	14.6
11287	9888.8 ft	09-06-052-11W5	2.655	0.52	46.4	2.679	1.11	38.6	15.0
11288	10852.3 ft	11-01-089-18W5	2.475	1.56	52.4	2.539	2.99	37.2	10.4
11289	10861.0 ft	11-01-089-18W5	2.545	0.84	58.4	2.577	1.44	30.9	10.7
11290	10890.0 ft	11-01-089-18W5	2.663	0.49	58.4	2.683	0.84	21.7	19.8

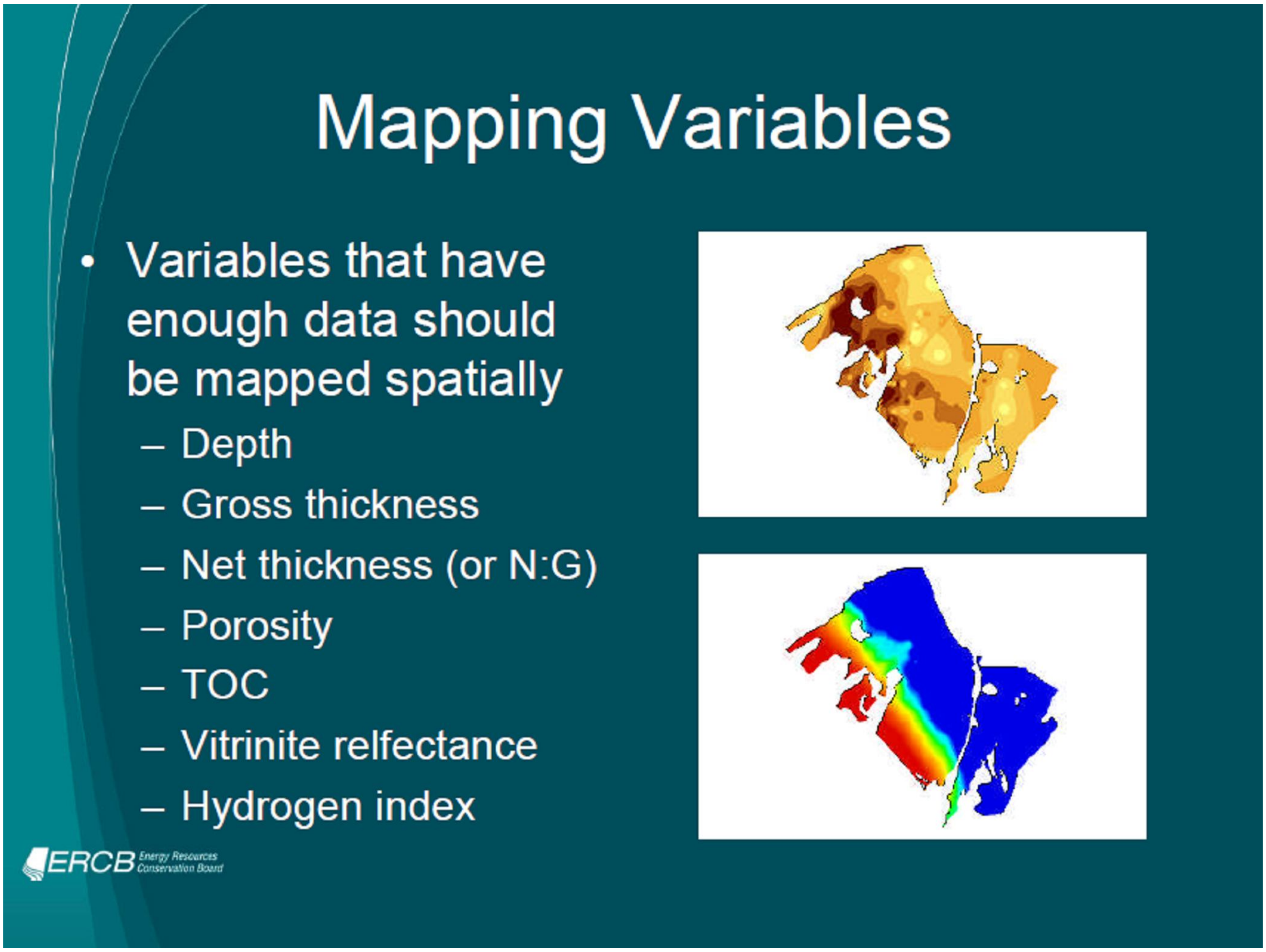
Dean Stark analysis provides insights into saturation, which a major factor in assessing shale reservoir potential but is difficult to determine. Standard testing methods were developed for conventional sandstone reservoirs and may or may not produce viable results for shales. Analysis in shale is problematic because of unconnected pores, nano-scale permeability, and bound water. Hydraulic creates an additional unknown in that the distinction between total porosity and effective porosity becomes unclear.



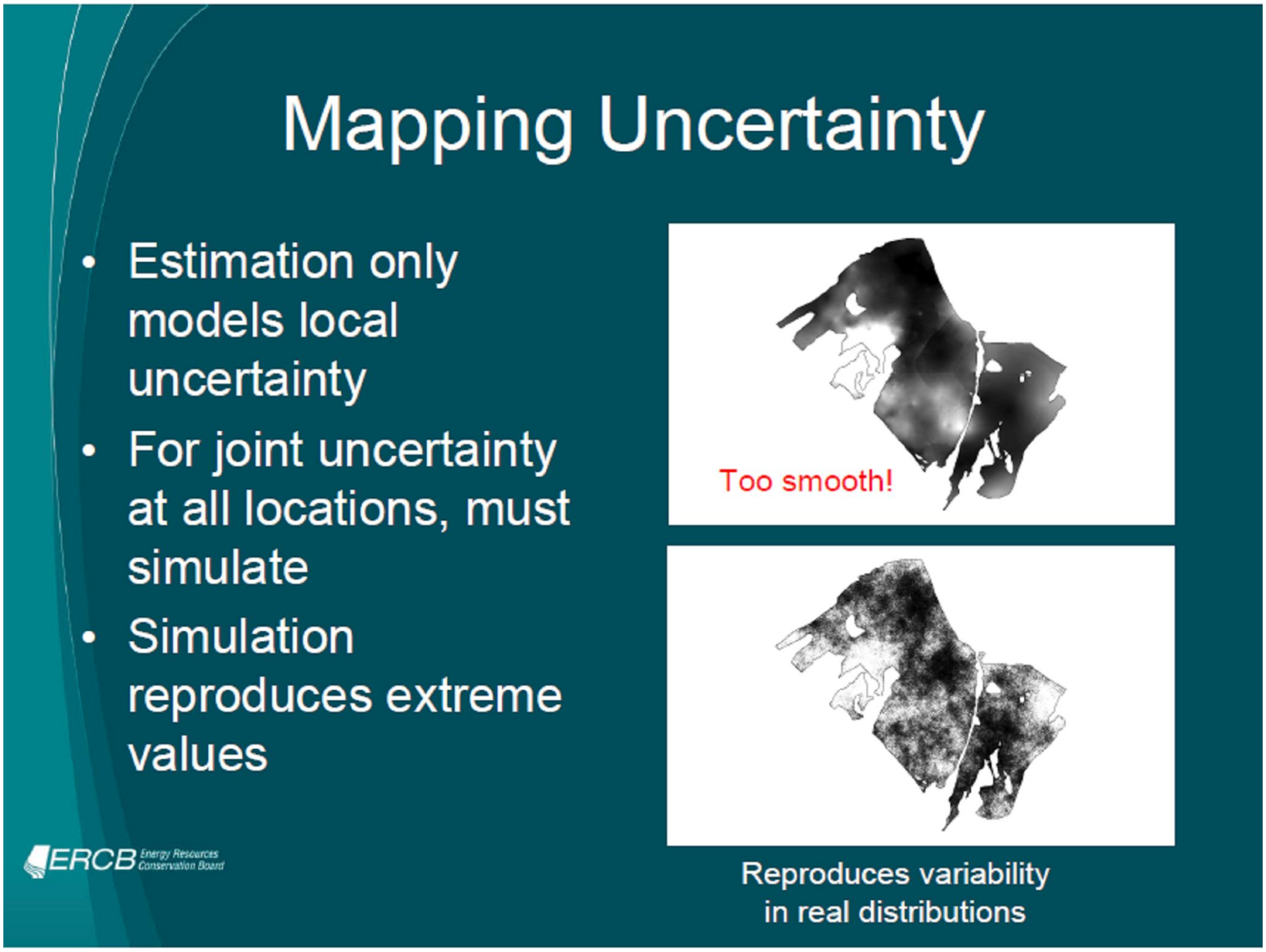
The first step is to spatially map variables for which there is sufficient data. This step is crucial because spatial variables associated with shale are large, with a mixture of sweet, dry, and hot spots. ERCB generally has data to spatially map depth, TOC, porosity, maturity, vitrinite reflectance, HI, gross thickness, and net thickness (or net to gross ratio). The second step is to use bivariate relationships to calculate other variables that are dependent on the spatially mappable variables.



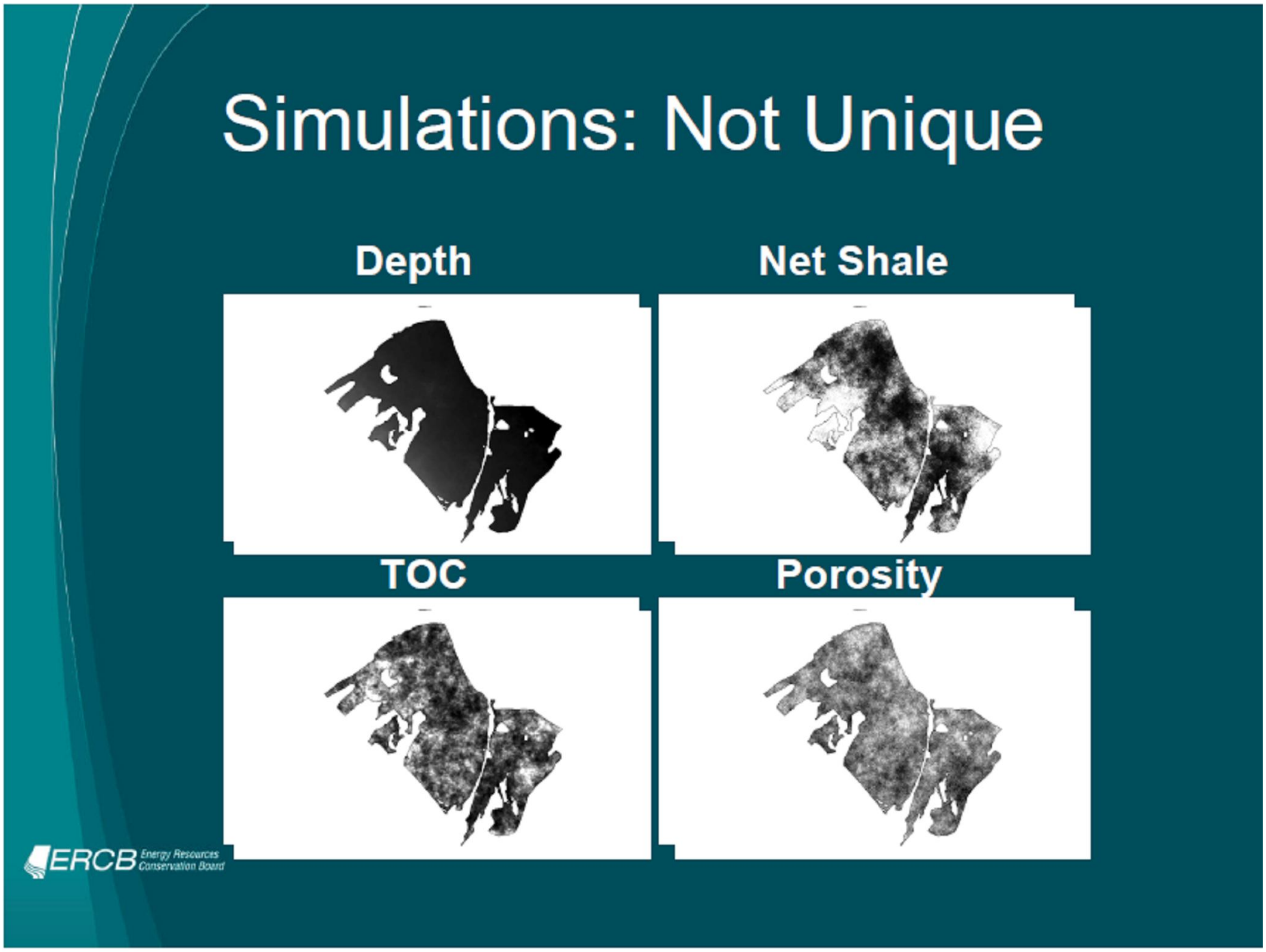
The third step of the workflow is to estimate those variables that cannot be mapped and do not have clear or definable relationships with other data. The resources are then calculated section-by-section and summarized by areas as desired. Simulation is incorporated to quantify the joint uncertainty in the total resources.



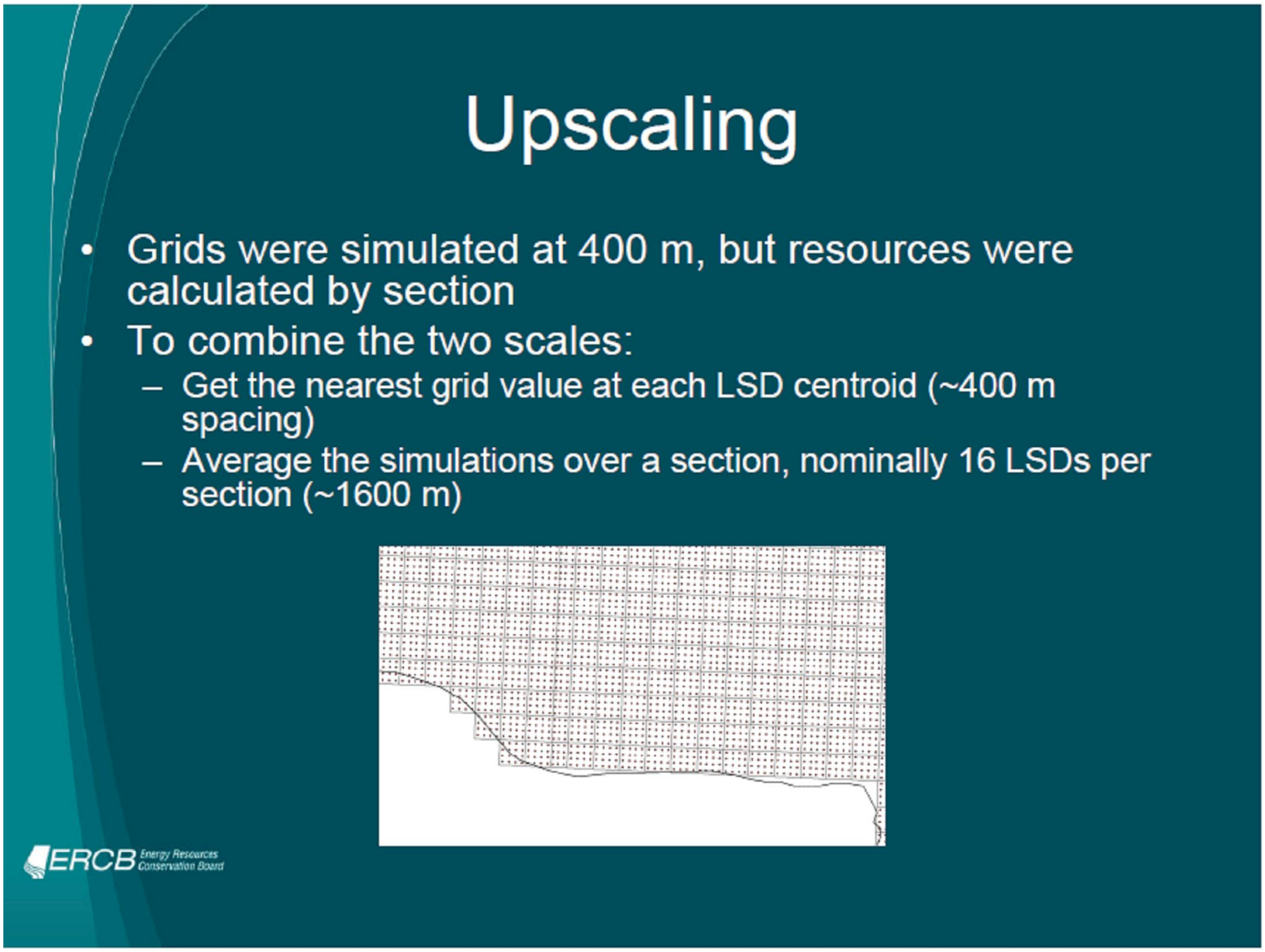
The variables that are mapped are the data from geological picks and log analysis, as well as any maturity or fluid distribution information that is available.



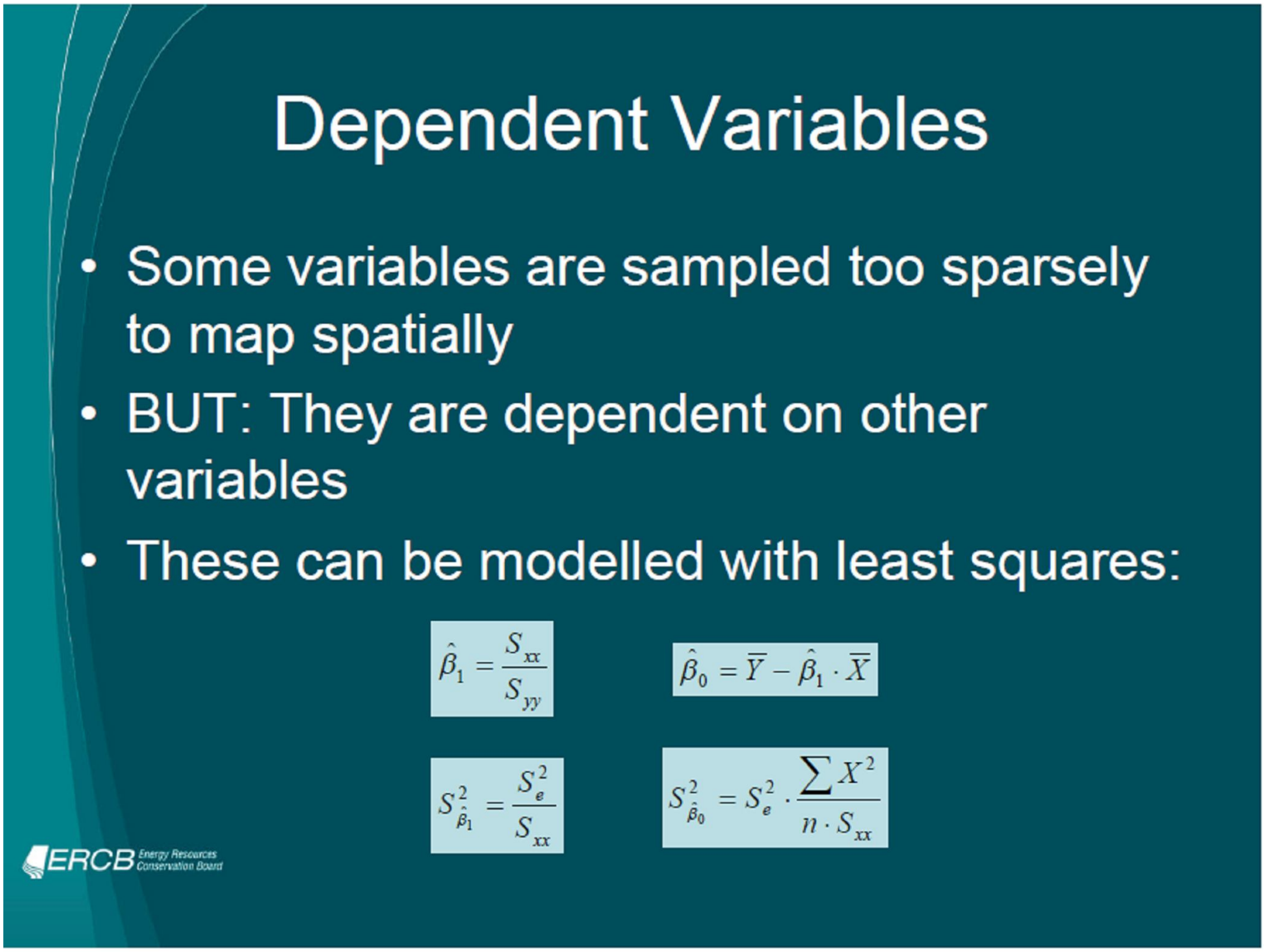
Estimation (e.g. kriging) only models local uncertainty; simulation is used for joint uncertainty at all locations simultaneously.



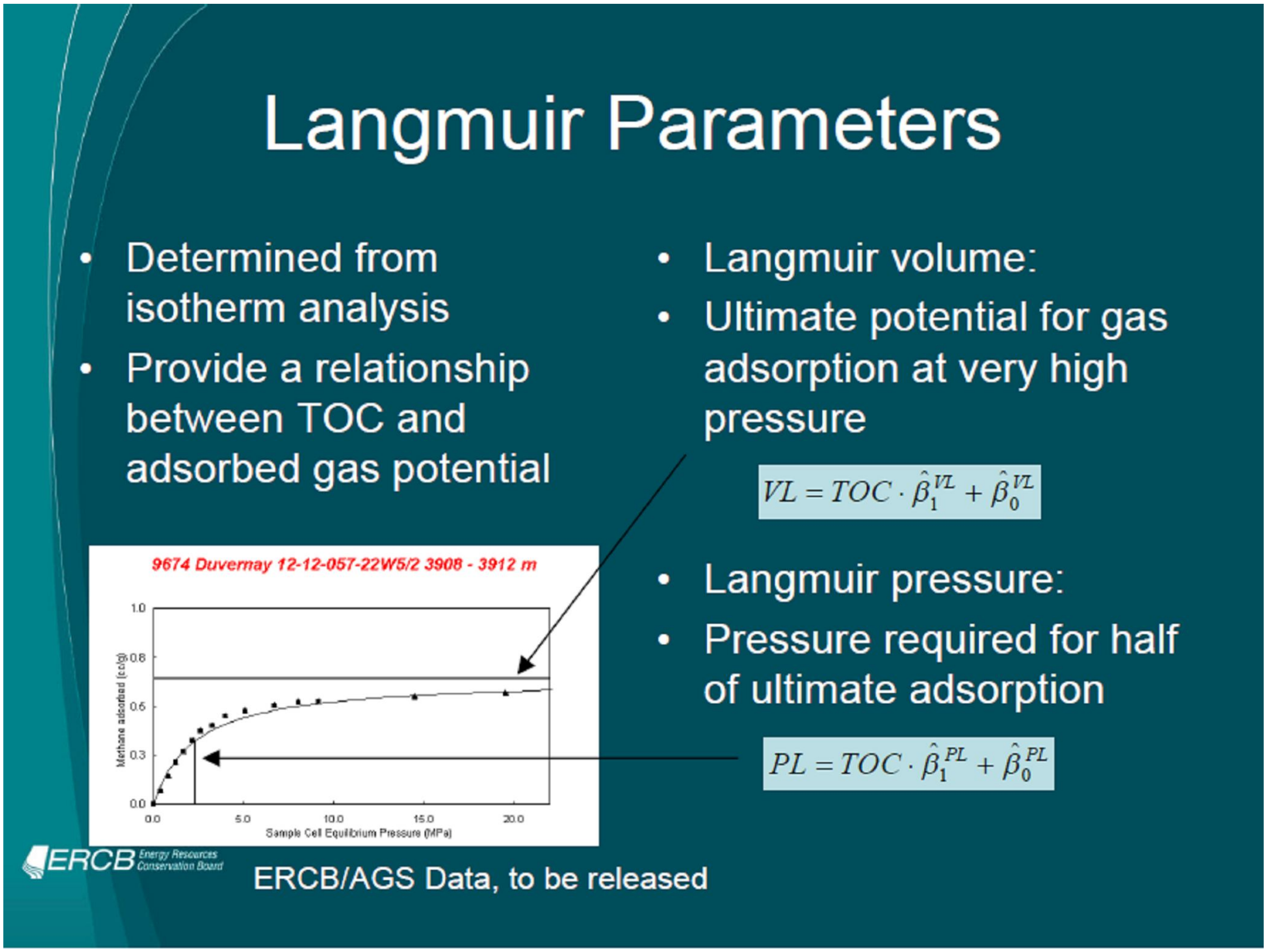
Simulated realizations are not unique; together, they reproduce variability seen in real data distributions.



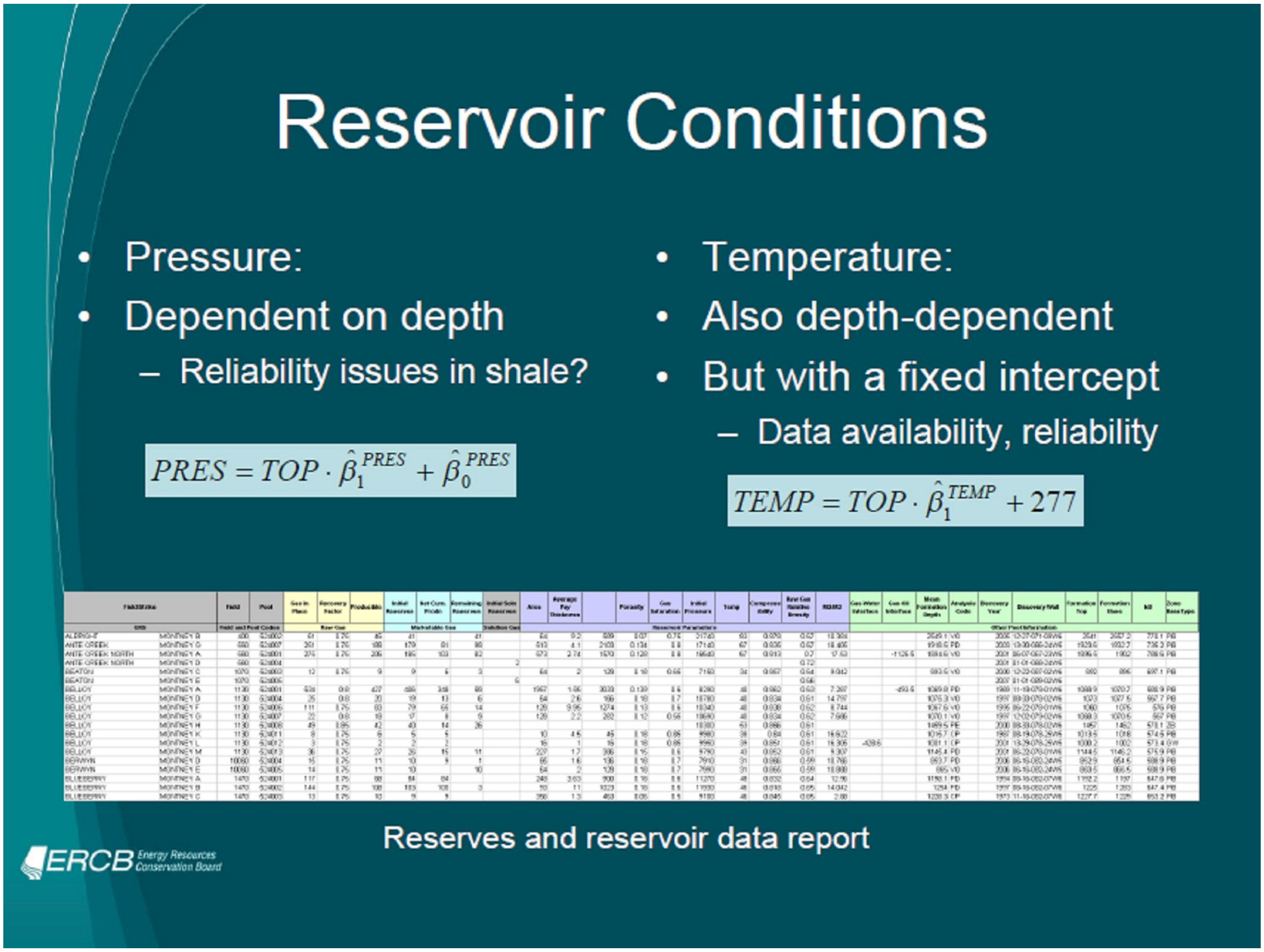
The simulated results are changed from the scale of the gridding algorithm to a more convenient scale for resource calculations that aligns with the Alberta township system.



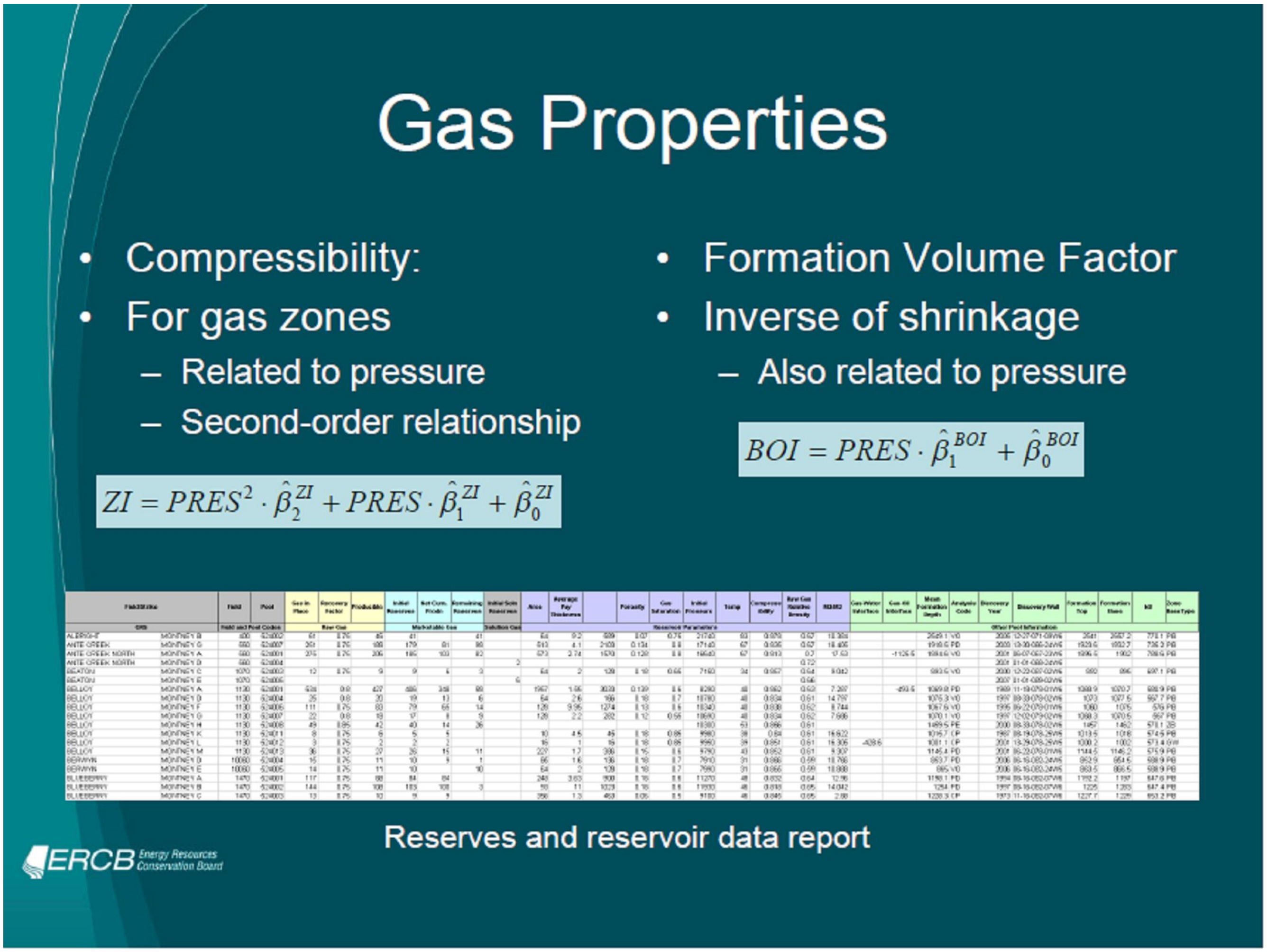
Dependent variables are generally sampled too sparsely to map spatially; however, they are dependent upon other variables and this bivariate relationship can be modeled with least squares, incorporating uncertainty in the slope and intercept parameters.



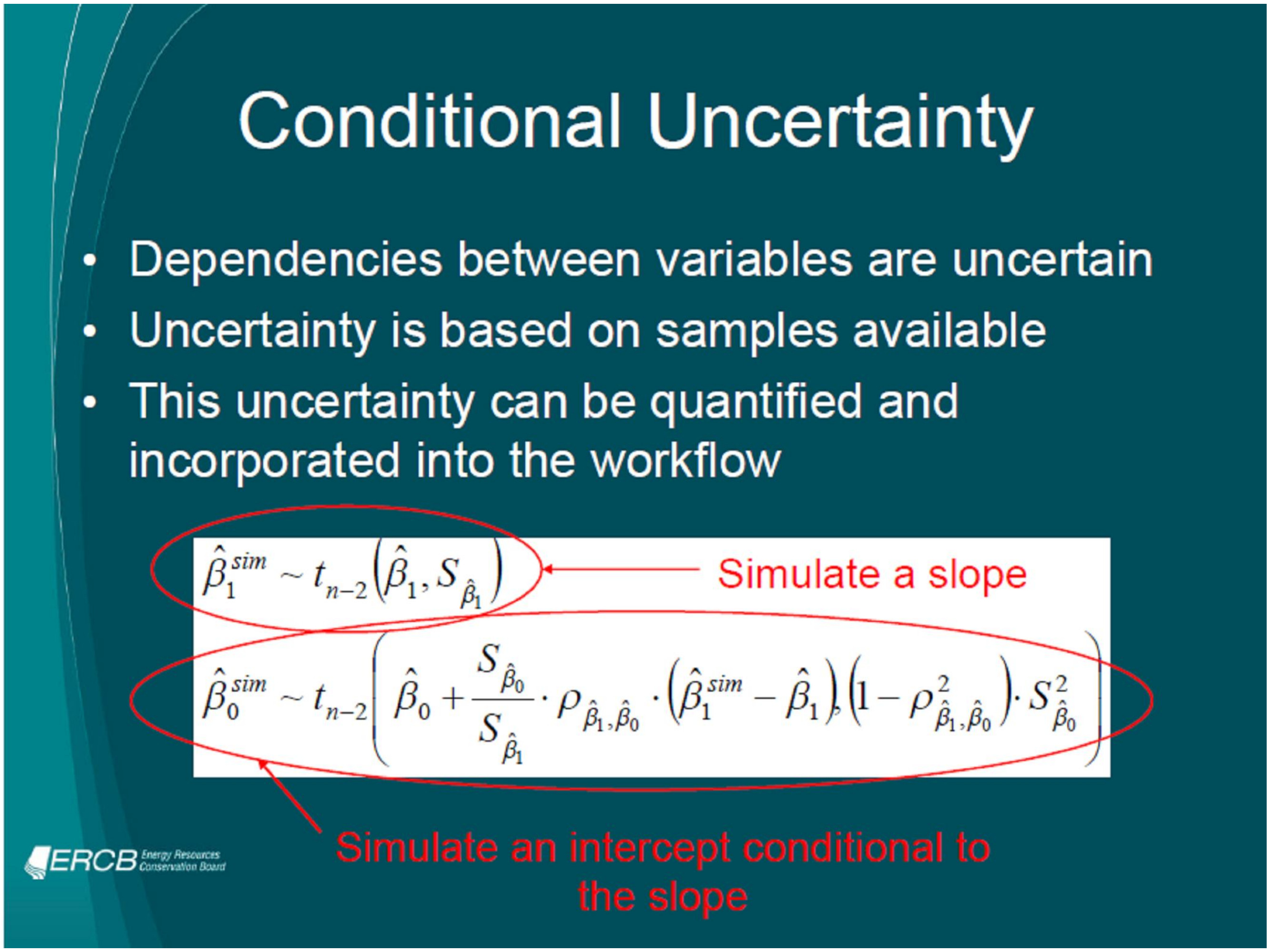
Langmuir parameters are evaluated to provide a relationship between TOC, pressure, and adsorbed gas content.



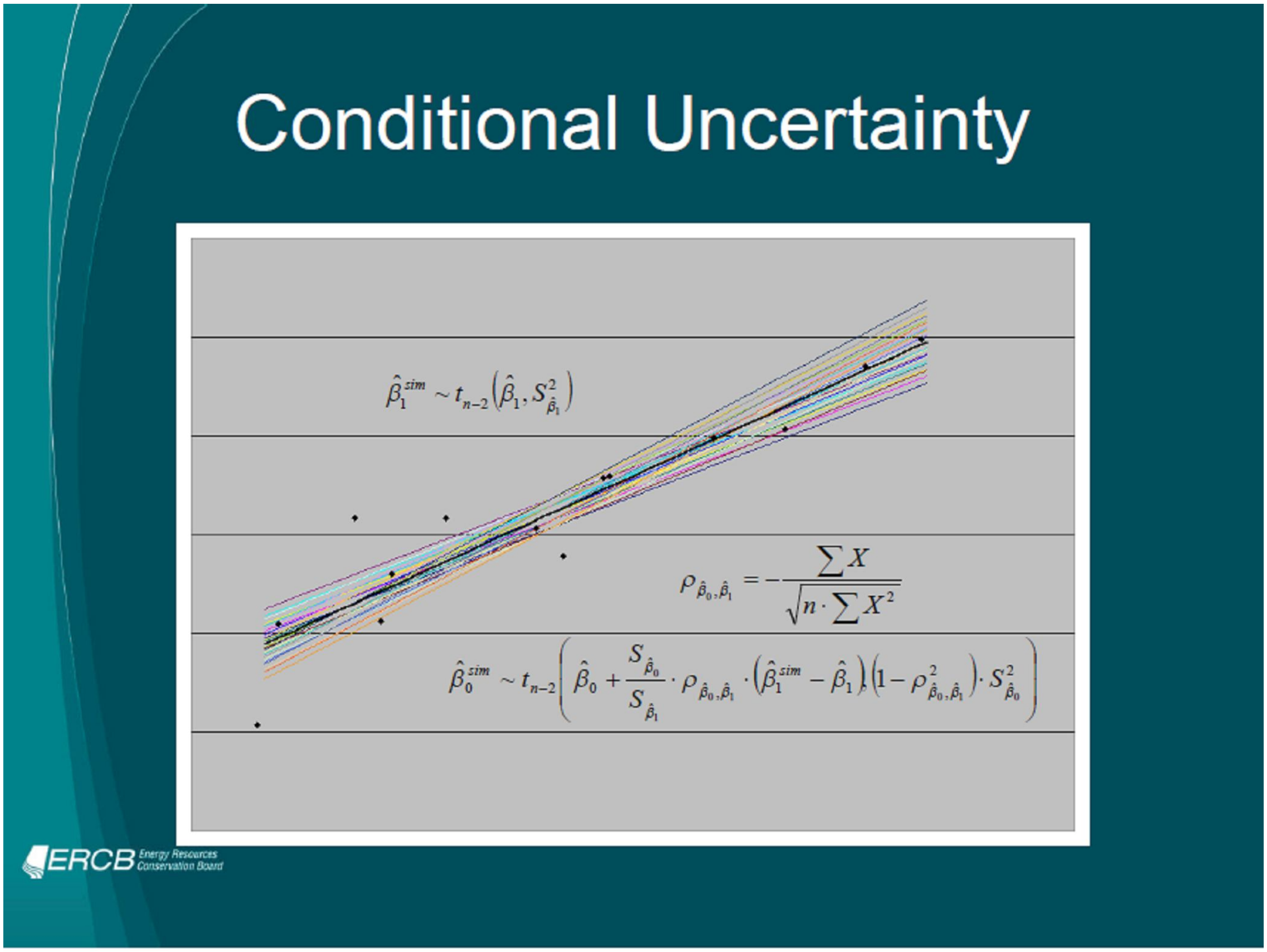
Analog or in-communication reservoir data is all that is available at this early stage of shale resource assessment. As drilling is undertaken the reservoir data can be updated and improved.



Gas and oil properties also must be taken from other nearby formations, possibly sourced by the shale being studied.



Conditional uncertainty derives from the fact that dependencies between variables are uncertain. Uncertainty is based on available samples. This uncertainty can be quantified and incorporated into the workflow.


Conditional Uncertainty
$\hat{\beta}_1^{sim} \sim t_{n-2}\left(\hat{\beta}_1, S^2_{\hat{\beta}_1}\right)$
$\rho_{\hat{\beta}_0,\hat{\beta}_1} = -\frac{\sum X}{\sqrt{n \cdot \sum X^2}}$
$\hat{\beta}_0^{sim} \sim t_{n-2}\left(\hat{\beta}_0 + \frac{S_{\hat{\beta}_0}}{S_{\hat{\beta}_1}} \cdot \rho_{\hat{\beta}_0,\hat{\beta}_1} \cdot \left(\hat{\beta}_1^{sim} - \hat{\beta}_1\right), \left(1 - \rho^2_{\hat{\beta}_0,\hat{\beta}_1}\right) \cdot S^2_{\hat{\beta}_0}\right)$
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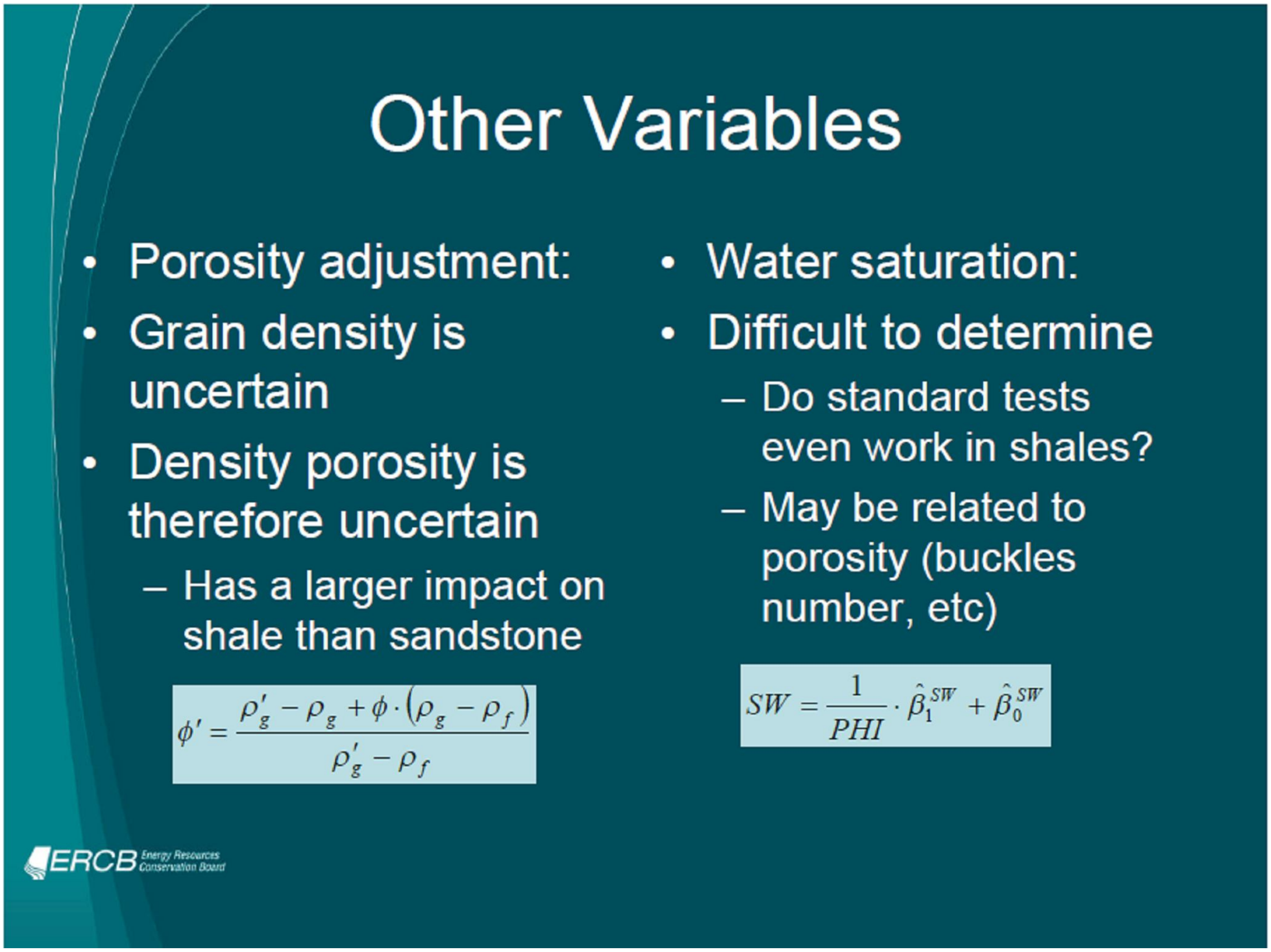
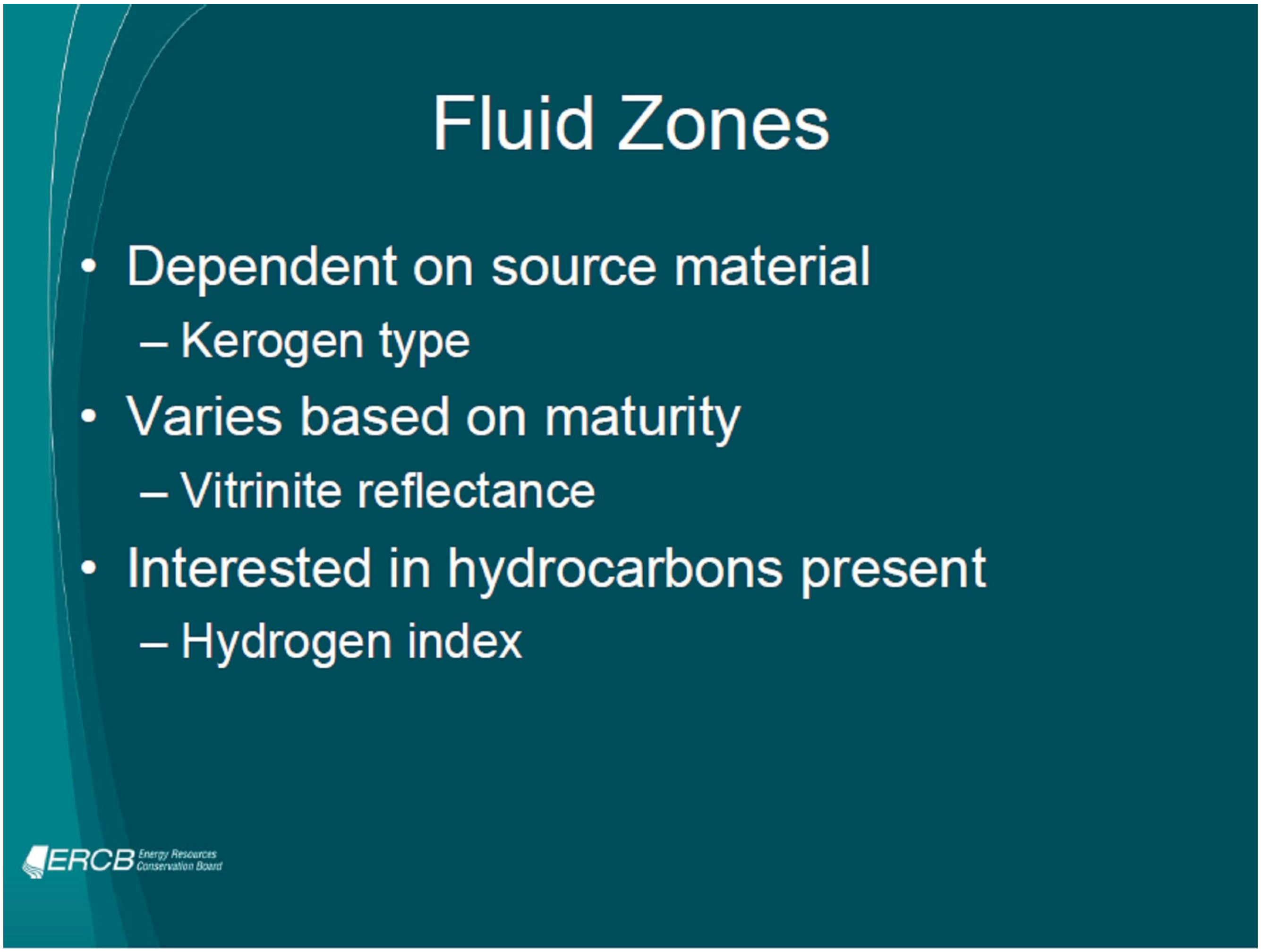
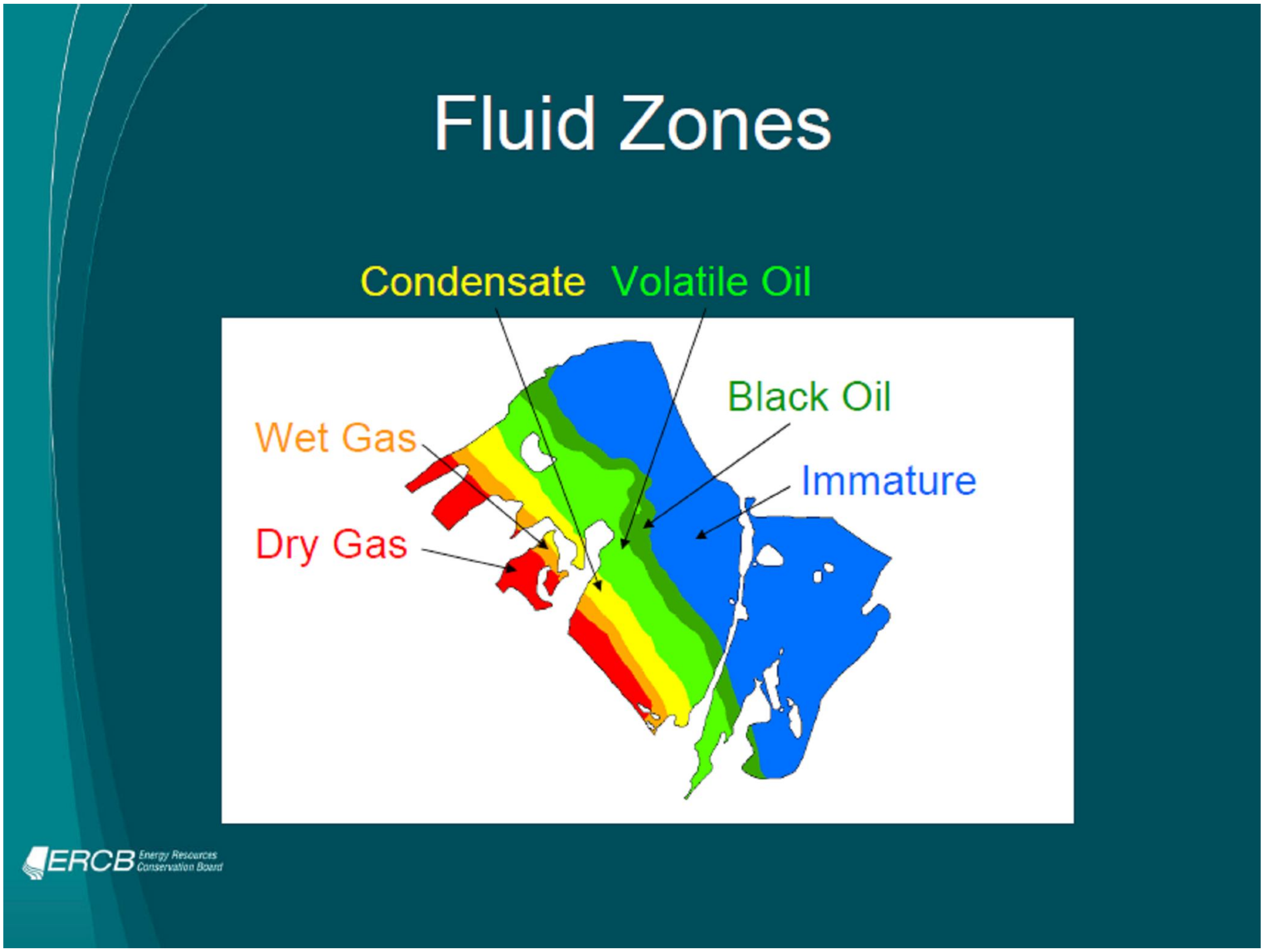


The next step is to calculate other variables, such as water saturation and a porosity adjustment based on uncertain grain density. In the case of limited samples, expert judgment has to be used. Water saturation is difficult to determine; it remains unclear whether standard tests work in shales.



“Shale gas” plays may contain many more fluids than just dry gas. In the current price environment the liquids are an important driver of project economics and must be quantified.



The variables used to evaluate the resource volume are plotted on maps, to provide a first degree of regional variability. However, the situation can be much more complex compared to the resulting representation as thresholds between zones can shift and there can be pockets of one kind of fluid in another.

Fluid Zones

Zone	HI	Ro	GOR
Immature		< 0.8	
Black Oil	350 +	> 0.8	0-310
Volatile Oil	200 – 350	> 0.85	310-570
Condensate	100 – 200	>1.0	570-10000
Wet Gas	60 – 100	> 1.2	
Dry Gas	< 60	> 1.35	

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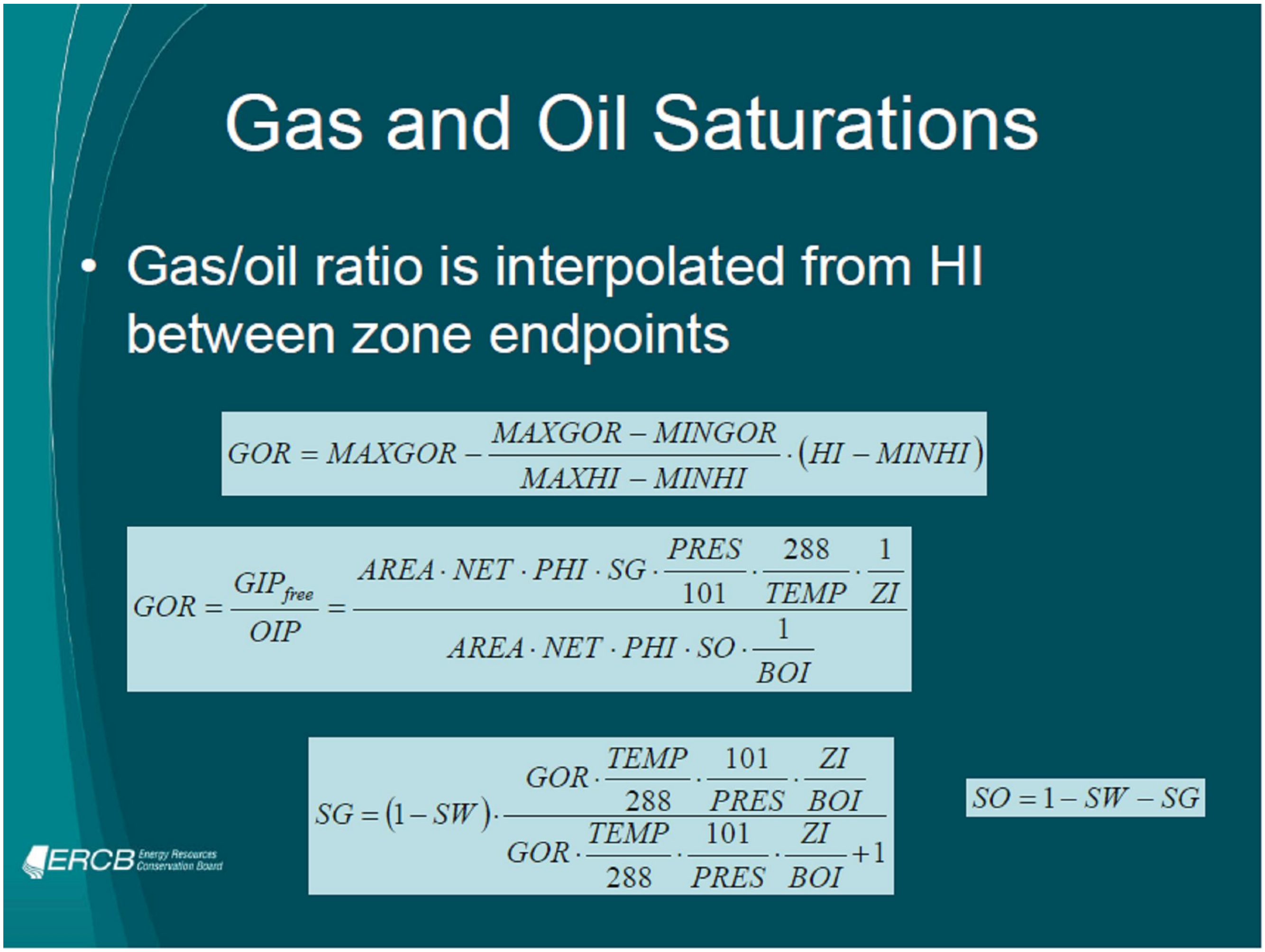
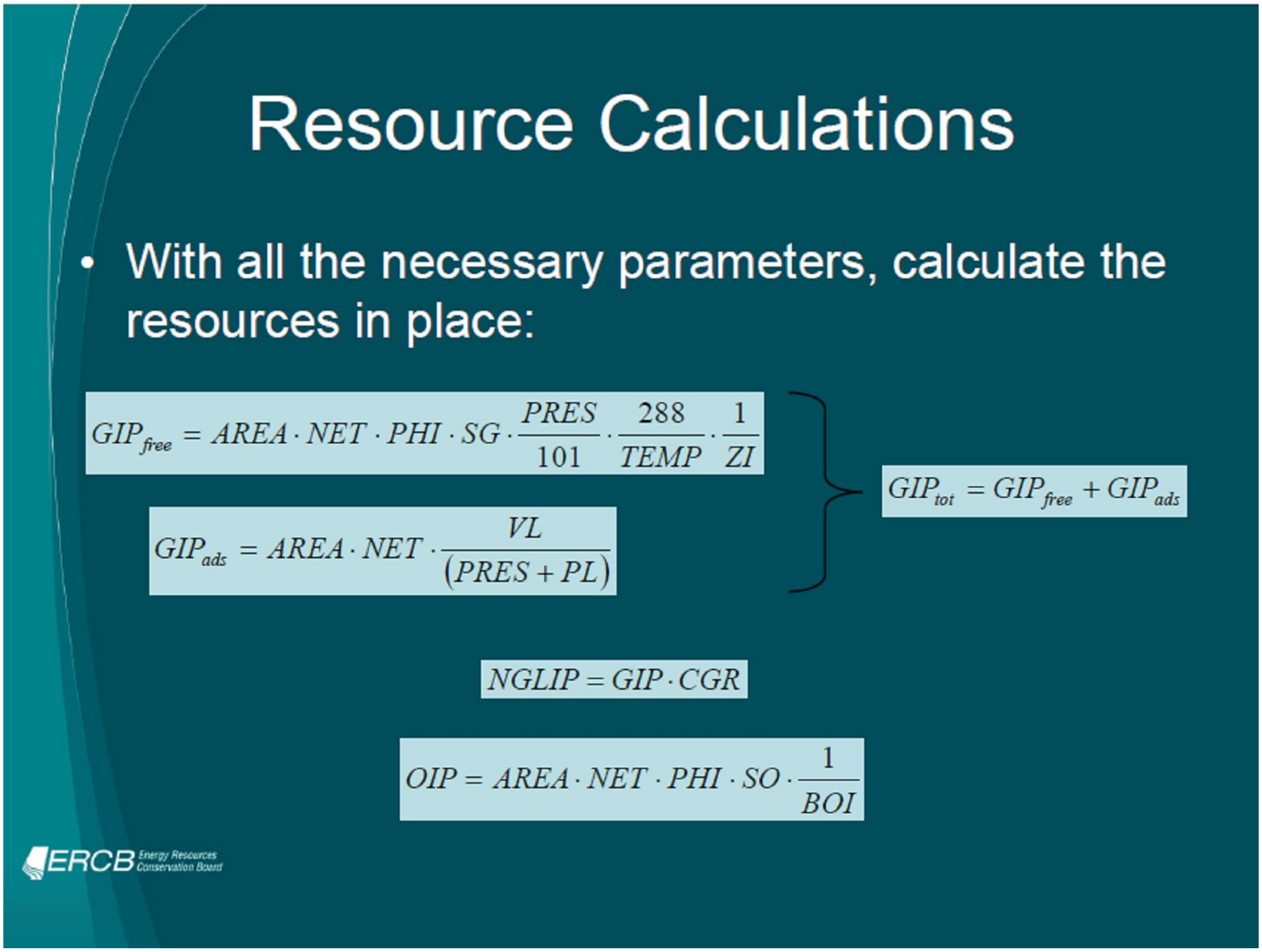
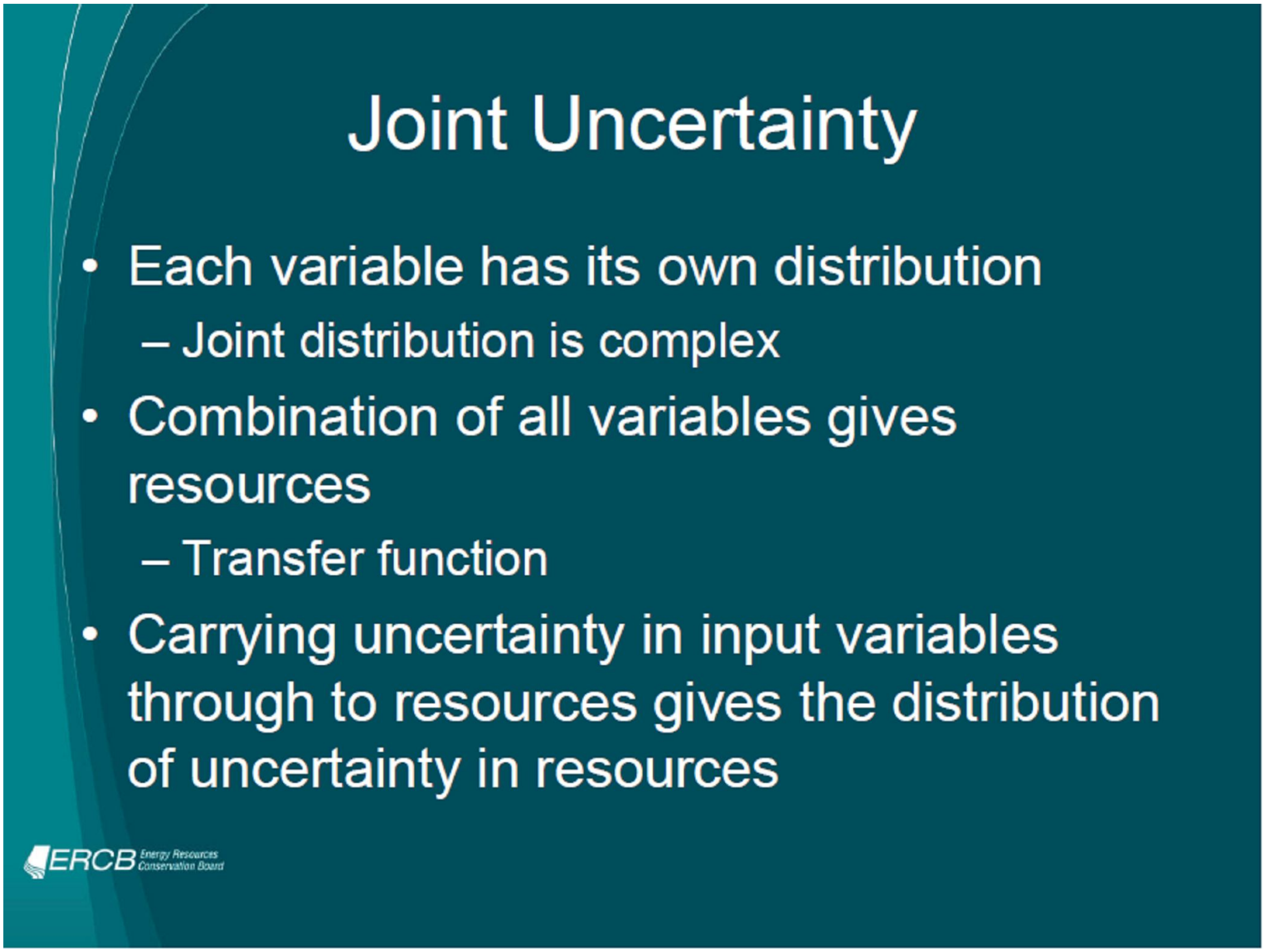
Cutoffs for the zones can be determined from published references or previous experience, and will most likely vary from shale to shale.



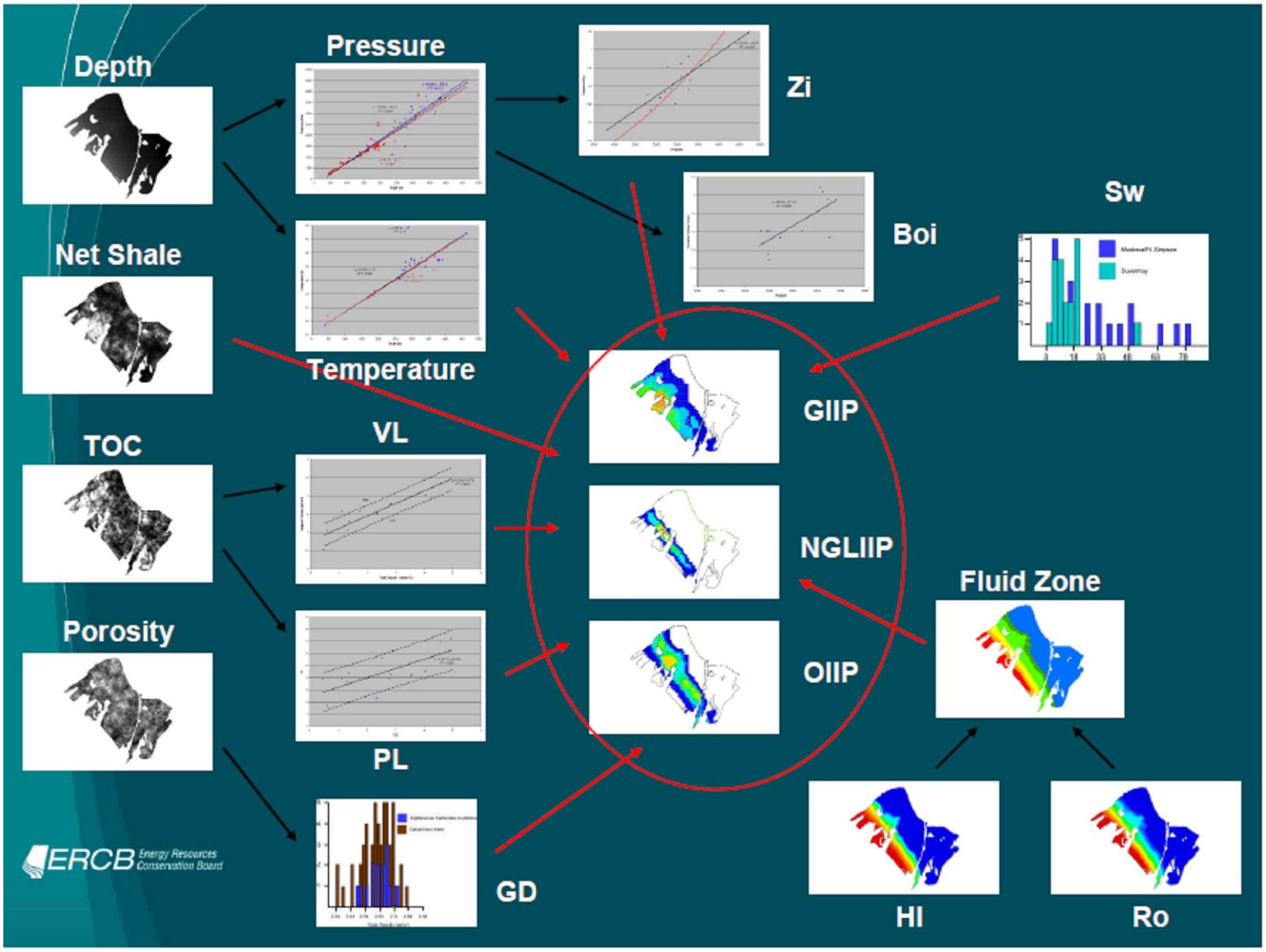
To ensure consistency in the fluid content, the gas-oil ratio is set based on the fluid zone maps and then the gas and oil saturation are back calculated. This also guarantees that pore space is not allocated to both oil and gas, double-counting the resource.



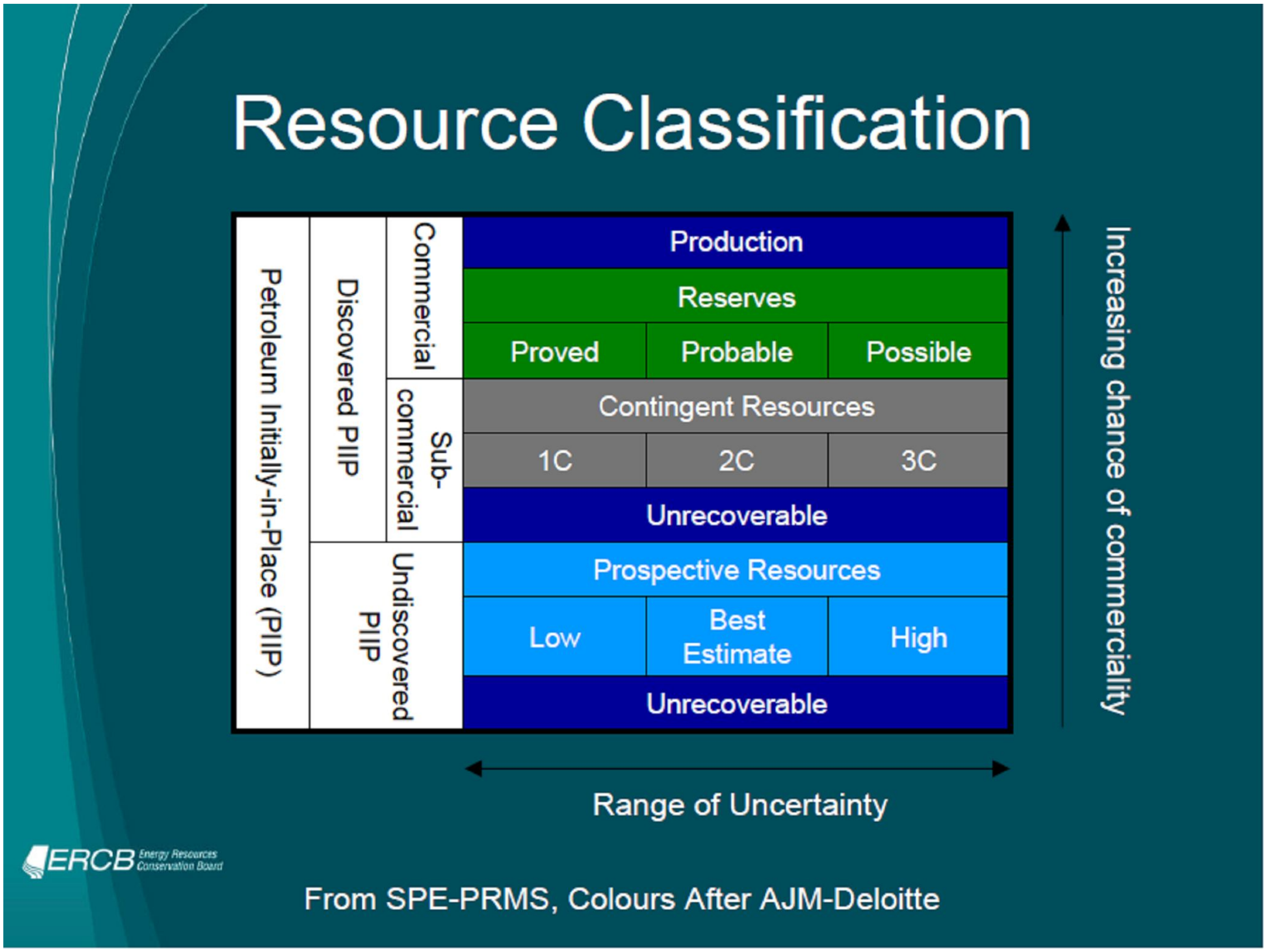
When all parameters are in place, the workflow method calculates the resources in place, on a section-by-section basis to provide a sum at a township and assessment unit scale. The method accounts for joint uncertainty.



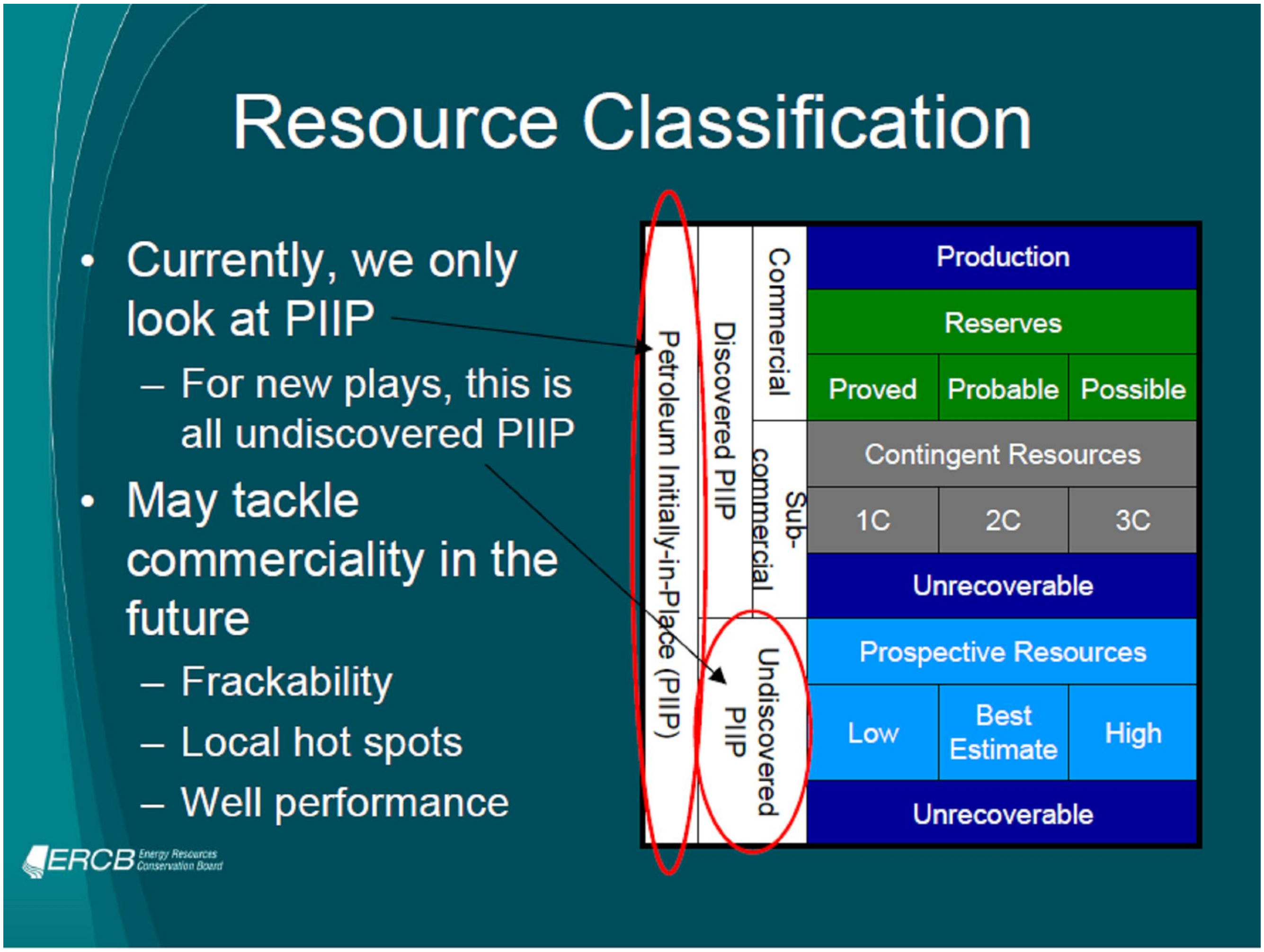
This workflow produces a distribution of shale gas resources accounting for the joint uncertainty in all of the variables.



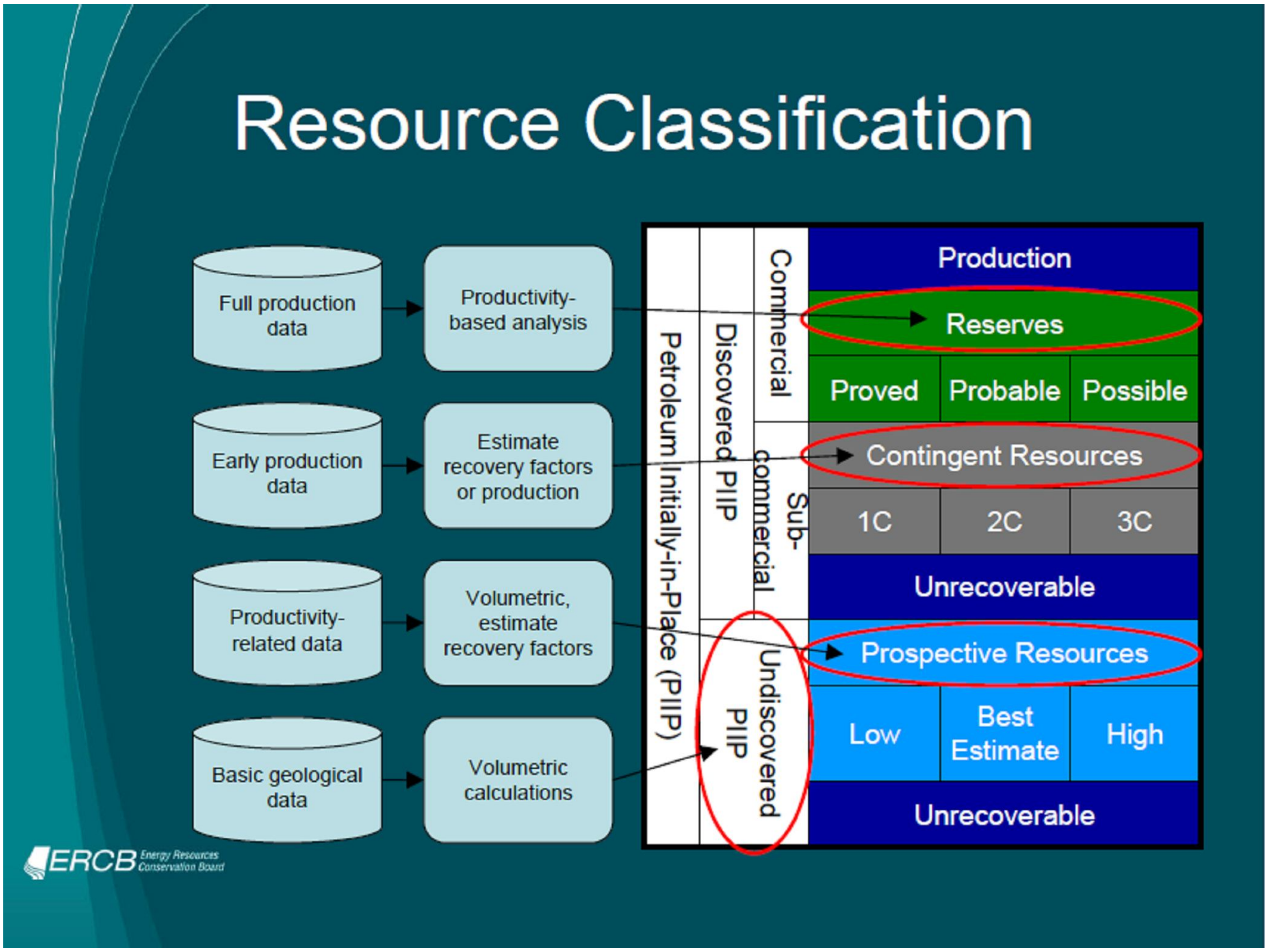
Integration of all data set into a resource evaluation for oil, condensate and gas.



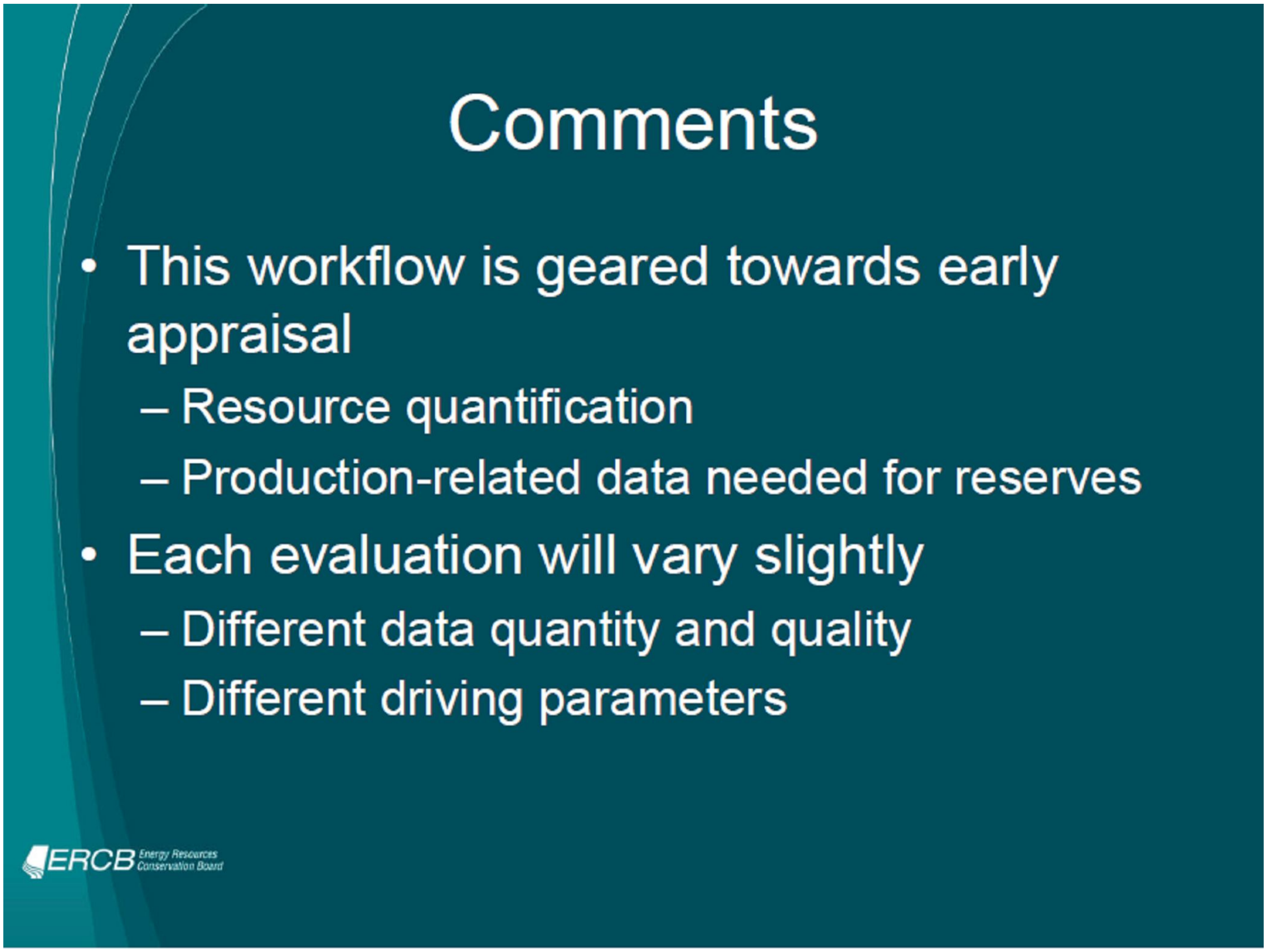
The McKelvey box resource classification system of the Petroleum Reserve Management System (PRMS).



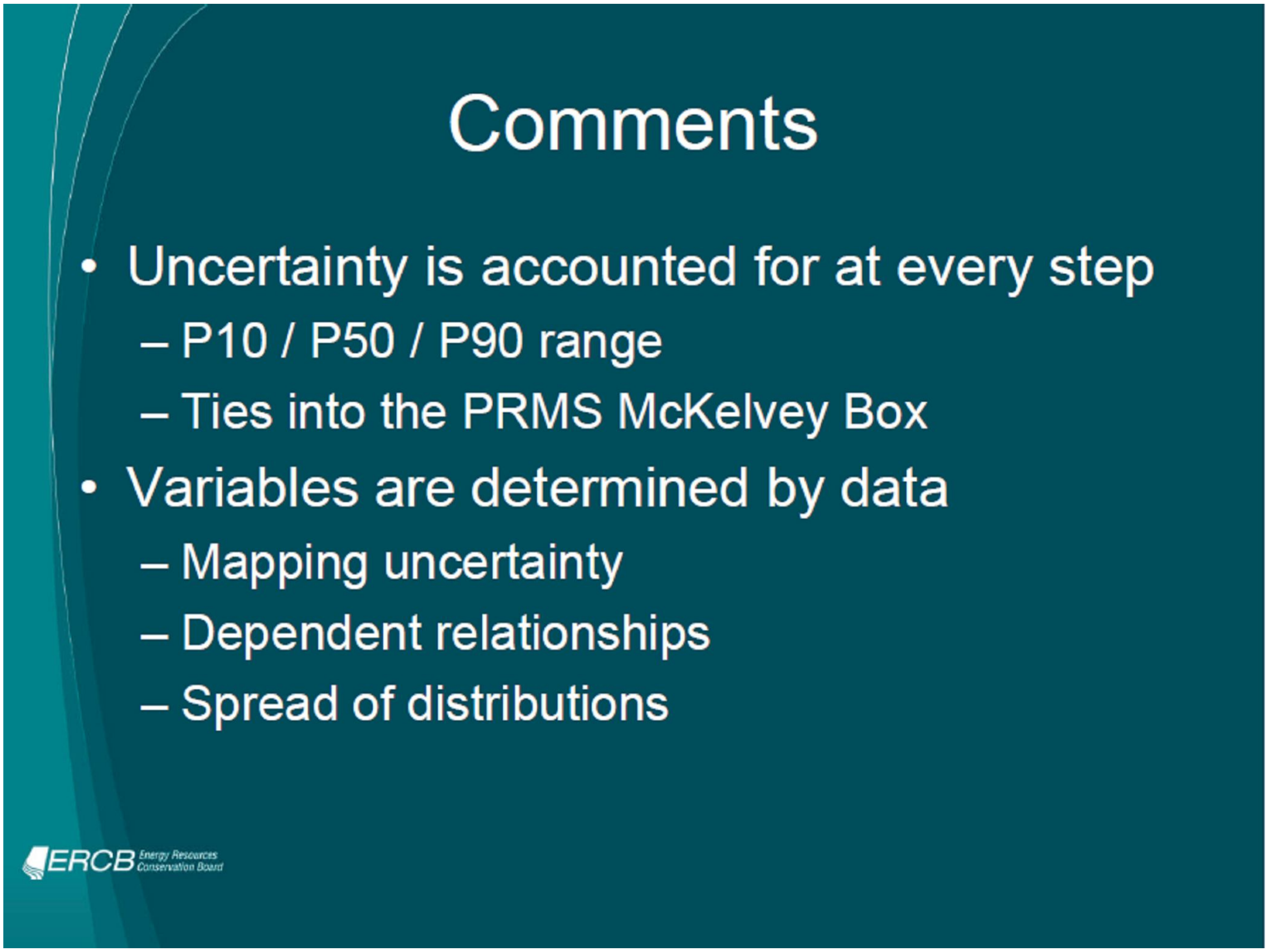
Currently, the ERCB has only considered petroleum initially in place (PIIP) for shales. For new plays, this is all undiscovered PIIP. The ERCB may tackle commerciality in the future, once production data is available.



Once early production data is available, the model can start to estimate recovery data for marketable gas. Additional production data will lead to real recovery data. Full production data will provide productivity-based analysis and a sense of the reserves, as is available in the United States



This workflow is geared towards early appraisal. Each evaluation will vary slightly due to data quantity and quality as well as different driving parameters.



Uncertainty was considered at every step when developing this workflow. Distributions are driven by the data whenever possible.

Discussion

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